CCC Interrogatory #021

Interrogatory

Reference:
Exhibit C1, Tab 1, Schedule 1, p. 3

Question(s):

Please further explain the calculation for the determining the appropriate amount to record in the DGCSVA in the circumstance that DNNP LP does raise debt financing during the current IR term. As part of the response, please advise whether the capital structure, for the purposes of deriving the variance to be recorded in the account, would be based on OPG's deemed structure (now applied to DNNP LP) or DNNP LP's actual capital structure after debt financing is acquired.

Response

As set out in Ex. H1-1-1, Section 6.2, the DNNP Generator Capital Structure Variance Account ("DGSVA") will record the revenue requirement impact of any differences between the capital structure and cost of debt for DNNP LP reflected in the nuclear payment amounts and DNNP LP's actual capital structure and cost of debt. Refer to Ex. L-C1-Staff-039 for further explanation of the operation of the DGSVA.

For the reasons set out in Ex. C1-1-1, the Application proposes a 100% equity funded capital structure for DNNP LP for the purposes of setting payment amounts in this proceeding. For clarity, this proposal is independent of the proposal for OPG's deemed capital structure. OPG and DNNP LP are separate legal entities that are independently prescribed under O. Reg. 53/05. Accordingly, the DGSVA will operate independently of OPG's deemed capital structure.

CCC Interrogatory #022

Interrogatory

Reference:
Exhibit C1, Tab 1, Schedule 1, Attachment 1, p. 19

Preamble:

The deemed equity ratio and authorized ROE must be considered together to determine whether the Fair Return Standard has been met.

Question(s):

Please confirm that the ROE percentage used by Concentric in its analysis of the appropriate capital structure is 9.11%.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

Correct. As described in Concentric's report (Ex. C1-1-1, Attachment 1, at 10 of 109), the OEB updated its cost of capital framework in EB 2024-0063, revising the formula used to establish the return on equity ("ROE") and updating other cost of capital parameters such as the deemed long-and short-term debt rates. In its decision in that matter, the OEB found that it would "continue the practice of addressing material differences [in OEB regulated utilities] through the capital structure." Concentric's report, therefore, focuses on OPG's deemed capital structure and whether it, along with the other components of OPG's cost of capital, meets the FRS. In doing so, Concentric assumed OPG's cost of capital would reflect the generic authorized ROE in Ontario.

CCC Interrogatory #023

Interrogatory

Reference:
Exhibit C1, Tab 1, Schedule 1, Attachment 1, p. 27

Question(s):

a) Please provide Figure 3 in tabular format.

b) Please provide the nuclear/hydro split by production (actual / forecast) in the same format as Figure 3 and in tabular format.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Please see the provided workpaper "CEA Fig 3 Nuclear Hydro Workpaper.xlsx" for the requested file. For convenience, we have additionally provided it as Attachment 1.

b) Please see Attachment 2 for the requested figures and data in electronic format.

CCC Interrogatory #024

Interrogatory

Reference:
Exhibit C1, Tab 1, Schedule 1, Attachment 1, p. 33

Question(s):

a) Please confirm that the main peer group reflected in Figure 9 is the same as the Concentric proxy group.

b) For each of the proxy companies in the analysis shown in Figure 9, please provide the company-specific 2022-2029 capital expenditures.

c) For each of the proxy companies in the analysis shown in Figure 9, please provide 2022-2024 regulated net plant.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Confirmed.

b) Please see Attachment 1 for the requested data.

c) See the answer to part b).

CCC Interrogatory #025

Interrogatory

Reference:
Exhibit C1, Tab 1, Schedule 1, Attachment 1, pp. 5, 41, 44

Preamble:

Concentric's conclusion is that, on balance, OPG's regulatory risk remained relatively stable since EB-2016-0152 and EB-2020-0290 rate applications, with some aspects of the risk decreasing and others increasing.

OPG's rates for its prescribed hydroelectric facilities were last set in EB-2016-0152 using a price-cap index Custom IR framework prior to being set legislatively at the 2021 rate for the 2022-2026 period. Under the price-cap framework, rates are set based on a cost of service approach for a test year, which is then escalated in subsequent years of the rate term by an inflation and productivity factor. Concentric understands that in this application, OPG is proposing to continue to set regulated hydroelectric rates using a price-cap index Custom IR framework but with the addition of a custom capital factor designed to ensure adequate funding for capital projects required over the forecast period.

Question(s):

a) Please confirm that in EB-2016-0152, OPG's hydroelectric payment amounts were established using a price-cap IR mechanism with no forward test year rebasing (i.e., hydroelectric payment amounts as were set in a previous proceeding were escalated under PCI with no 2017 rebasing).

b) Please provide a table that lists all of the changes to the regulatory treatment of OPG (both nuclear and hydroelectric businesses) and advise whether each change is an increase or decrease to OPG's regulatory risk.

c) Please provide a list of all deferral and variance accounts that OPG was approved in EB-2020-0290 and all of the accounts that OPG proposes in the current proceeding. Please provide a discussion of the change in risk related to deferral account coverage.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Confirmed. As described in the OEB's decision in EB-2016-0152, at 122, "OPG proposed to use the hydroelectric payment amounts approved in EB-2013-0321, adjusted for a tax allocation, as the going-in payment amounts for the IR term."

b) See Concentric's report (Ex. C1-1-1, Attachment 1) at 40 to 44 for a summary of key developments affecting OPG's regulatory risk since EB-2016-0152 and EB-2020-0290. Please also see Chart 1 below for a summary of that discussion.

Chart 1 – Summary of Key Developments

Regulatory Development	Comment on OPG Risk Impact
Ontario Regulation 53/05 is proposed to be amended to implement CCR that would allow OPG to earn a debt return on CWIP during the PRP construction period.	• This change, while not providing a full return on capital to OPG because it considers only a long-term debt return, will provide cash flows to OPG during the course of the PRP relative to what it would have been otherwise. • OPG's ability to recover interest on CWIP for the PRP is a risk reducing mechanism; however, it is important to recognize that it is being implemented to support the Company's credit profile during the otherwise risk escalating $26.8 billion PRP by advancing cash flows and that OPG will remain exposed to nuclear construction related risks during the PRP, with project costs subject to the OEB's review. In other words, while the CCR Regulation reduces OPG's risk on the PRP relative to a mega project without CCR, it does not eliminate the project's risks and OPG's overall capital program is such that its credit metrics will remain under pressure even when CCR is taken into account (as discussed below regarding financial risk).
OPG continues to have a number of deferral and variance accounts as part	These accounts serve to mitigate certain of the Company's business and operating

Regulatory Development	Comment on OPG Risk Impact
of its regulatory framework for nuclear and hydroelectric facilities.	risks, although they are subject to a prudence review by the OEB (e.g., the Capacity Refurbishment Variance Account and the Nuclear Development Variance Account) and some relate to unique features of the regulatory framework (e.g., Rate Smoothing Deferral Account represents a deferral of costs, Bruce Lease Net Revenues Variance Account pertains to an unregulated activity, Pickering B Variance Account returns net revenues to customers). See the response to part c) for further discussion of OPG's deferral and variance accounts.
OPG reached its first ever near-complete settlement on its major rates application in EB-2020-0290 as approved by the OEB.	• While the EB-2020-0290 settlement resulted in reductions from the Company's proposed cost levels for recovery and the proposed equity thickness, the ability to achieve rate settlements is generally considered positive from an investor's perspective. • While achieving a settlement, the OEB's decision on the few unsettled issues resulted in a significant capital project disallowance. Specifically, the OEB disallowed $94 million in capital costs, plus carrying costs, related to the OPG's Heavy Water Storage and Drum Handling Facility project, as part of the DRP, due to an imprudence finding.
In June 2023, the OEB denied OPG's application for a variance account to capture increased compensation costs due to the repeal of the Protecting a Sustainable Public Sector for Future Generations Act, which had limited annual wage and total compensation	OPG estimated the incremental cost impact of this repeal to be approximately $188 million.

Regulatory Development	Comment on OPG Risk Impact
increases for Ontario public sector employees, and which limits OPG had reflected in its revenue requirement in EB-2020-2090.	
In 2024, OPG reached a complete settlement on its deferral and variance account clearance application (EB-2023-0336) as approved by the OEB.	Achievement of a settlement is positive but also commonly achieved by OPG in deferral and variance account clearance applications.
In 2024, the OEB's decision in the generic cost of capital proceeding reduced Ontario utilities' authorized base ROE by 25 basis points.	Ontario's generic ROE has been in place since 2009, so the continued use of a formula is risk neutral. The OEB, however, reduced the formulaic ROE at a time when the cost of capital for regulated utilities in North America has been increasing since 2020. This introduces increased financial risk for Ontario utilities, including OPG, reducing cash flows relative to the previous formula.

c) As described in Concentric's report (Ex. C1-1-1, at 41), OPG continues to have a number of deferral and variance accounts as part of its regulatory framework for nuclear and hydroelectric facilities. These accounts serve to mitigate certain of the Company's business and operating risks, although a number are subject to a prudence review by the OEB (e.g., the Capacity Refurbishment Variance Account and the Nuclear Development Variance Account) and some relate to unique features of the regulatory framework (e.g., Rate Smoothing Deferral Account represents a deferral of costs, Bruce Lease Net Revenues Variance Account pertains to an unregulated activity, Pickering B Variance Account returns net revenues to customers). Please see Chart 2 below for a list of all deferral and variance accounts that OPG was approved in EB-2020-0290 and all of the accounts that OPG proposes in the current proceeding. Because Concentric reviewed changes in OPG's regulatory and operating environment since EB-2016-0152, as well as prospectively, the chart also provides deferral and variance accounts that OPG was approved in EB-2016-0152, as well as deferral and variance accounts that OPG is requesting to discontinue in this proceeding.

Chart 2 – Deferral and Variance Accounts

Account	EB-2016-0152	EB-2020-0290	EB-2025-0297	Comment on OPG Risk Impact
Hydroelectric Water Conditions Variance Account	✓	✓	✓	No change (account in place since EB-2016-0152).

Account	EB-2016-0152	EB-2020-0290	EB-2025-0297	Comment on OPG Risk Impact
Hydroelectric Incentive Mechanism Variance Account	✓	✓	Requested for discontinuation	If this account is discontinued it would have a positive impact on OPG's risk as it possibly allows OPG to retain more incentive revenues.
Hydroelectric Surplus Baseload Generation Variance Account	✓	✓	✓	No change (account in place since EB-2016-0152).
Ancillary Services Net Revenues Variance Account – Hydroelectric Sub-Account	✓	✓	✓	No change (account in place since EB-2016-0152).
Income and Other Taxes Variance Account	✓	✓	✓	No change (account in place since EB-2016-0152).
Capacity Refurbishment Variance Account	✓	✓	✓	No change (account in place since EB-2016-0152).
Pension and OPEB Cost Variance Account	✓	✓	✓	No change (account in place since EB-2016-0152).
Hydroelectric Deferral and Variance Over/Under Recovery Variance Account	✓	✓	✓	No change (account in place since EB-2016-0152).
Gross Revenue Charge Variance Account	✓	✓	✓ Expansion proposed	Neutral on balance. Proposed changes would expand the flow back to customers of gross revenue charges while capturing changes in the gross revenue charge due to legislative or regulatory changes.
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Variance Account – Primary and Contra Sub-Accounts, and Carrying Charges Sub-Account	✓	✓	✓	No change (account in place since EB-2016-0152).
Nuclear Liability Deferral Account	✓	✓	✓	No change (account in place since EB-2016-0152).

Account	EB-2016-0152	EB-2020-0290	EB-2025-0297	Comment on OPG Risk Impact
Nuclear Development Variance Account	✓	✓	✓	No change (account in place since EB-2016-0152).
Bruce Lease Net Revenues Variance Account	✓	✓	✓	No change (account in place since EB-2016-0152).
Nuclear Deferral and Variance Over/Under Recovery Variance Account	✓	✓	✓	No change (account in place since EB-2016-0152).
SR&ED ITC Variance Account	✓	✓	✓	No change (account in place since EB-2016-0152) Although proposed to be expanded to the hydroelectric facilities, effect is generally neutral, ensuring the benefits of certain tax credits are passed on to ratepayers.
Rate Smoothing Deferral Account		✓	✓	Neutral as of 2027 as no further entries, but negative compared to 2016, as rate smoothing as a concept defers cash flows.
Impact for IFRS Deferral Account		✓	✓	Positive, albeit impacts unknown .
Earnings Sharing Deferral Account		✓	✓	Increase in risk due to asymmetric structure of OPG's ESM, whereby OPG does not have protection from earnings that are less than its authorized return, but must share earnings that exceed its authorized return plus 100 basis points.
Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account		✓	✓	Neutral, as it allows OPG to record revenue requirement impacts resulting from Pickering station end of life date changes. Can result in credit positions.
Pickering Closure Costs Deferral Account			✓	Positive, as it allows OPG to recover employment related and non-capital related costs related to Pickering closure activities.
Pickering B Variance Account			✓	Neutral, as it allows OPG to record revenue requirement impacts of Pickering B extension activities, Pickering B preservation costs, offset by additional revenues generated from Pickering B output between January 1, 2026 and September 30, 2026. Can result in credit positions.

Account	EB-2016-0152	EB-2020-0290	EB-2025-0297	Comment on OPG Risk Impact
Pickering B Refurbishment Project Variance Account, effective January 1, 2026			✓	See discussion of CCR in response to part (b).
Darlington New Nuclear Project Variance Account, effective January 1, 2026			✓	Excluded; Concentric's report does not assess the DNNP.
Change of Laws Deferral Account			✓	Positive, if accepted by the OEB, as it would protect OPG from revenue and cost impacts due to change of laws (subject to prudence standard).
Global Hydroelectric Capital Variance Account			✓	Negative, if accepted by the OEB. The proposed account would be asymmetric in that an amount could be credited to ratepayers in the event the capital-related revenue requirements ("CRRR") determined based on actual capital in-service additions over the period is less than the CRRR underpinning the capital factor calculation. In the event the CRRR based on actual capital in-service additions is greater than the CRRR underpinning the C-factor, there would be no recovery from ratepayers through this account.
Clean Electricity ITC ("CEITC") Variance Account			✓	Neutral, as it is proposed to ensure benefits of CEITCs are passed on to ratepayers.
Payment Amount Shaping Deferral Account			✓	Negative, as cash flows are deferred under the shaping of revenue requirements.
Accounts are proposed by OPG to continue to record only amortization and interest: • Ancillary Services Net Revenues Variance Account –Nuclear Sub-Account				These accounts were previously terminated or are proposed by OPG to continue to record only amortization and interest. Neutral risk impact going forward.

Account	EB-2016-0152	EB-2020-0290	EB-2025-0297	Comment on OPG Risk Impact
• Pension & OPEB Cash Payment Variance Account • Pension & OPEB Cash Versus Accrual Differential Deferral Account • Incremental Cloud Computing Arrangement Implementation Costs Deferral Account • Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account • Clarington Corporate Campus Deferral Account • Sale of Unprescribed Kipling Site Deferral Account • Fitness For Duty Deferral Account • Pickering Life Extension Depreciation Variance Account • Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account • Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2017) Deferral Account				

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CCC Interrogatory #027

Interrogatory

Reference:
Exhibit C1, Tab 1, Schedule 1, Attachment 1, p. 51

Question(s):

Please provide a list of the A-Rated Canadian Utilities reflected in Figures 11 & 12.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

The A-rated Canadian utilities reflected in Figures 11 and 12 (Ex. C1-1-1, Attachment 1, p. 51) are Hydro One Inc., Enbridge Gas Inc., EPCOR Utilities Inc., CU Inc., Toronto Hydro Corporation, and Alectra Inc.

CCC Interrogatory #029

Interrogatory

Reference:
Exhibit C1, Tab 1, Schedule 1, Attachment 1, pp. 55-59

Question(s):

a) Please explain why Concentric selected Georgia, South Carolina and Florida for its comparison of O. Reg 53/05 to other jurisdictions.

b) Please advise whether there are other jurisdictions in North America that have large scale nuclear projects completed or abandoned. If so, please provide a list of those jurisdictions and a summary of the relevant nuclear cost recovery provisions.

c) For each of the three jurisdictions shown in Figure 13, please advise whether the CCR mechanisms allowed for the recovery of financing costs based on debt rates or WACC.

d) Please explain whether OPG's performance with respect to the completion of the DRP was incorporated into Concentric's analysis of risk related to future capital investments.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Concentric selected Georgia, South Carolina, and Florida because they represent the most relevant and instructive North American precedents for evaluating the provisions of O. Reg. 53/05 in the context of large-scale nuclear development. Specifically, these jurisdictions were selected because included provisions governing: 1) approval of the need for the new generating plant before construction begins (i.e., the utility does not face the risk of not being subsequently allowed to close the project to rate base upon completion); 2) recovery of prudently-incurred construction and financing costs before the plant goes into service; 3) recovery of costs that exceed the originally approved projections, subject to a prudence review by the regulator; and 4) recovery of prudently incurred construction costs if the project is abandoned.

b) Concentric is aware of other North American jurisdictions with large-scale nuclear construction experience, but beyond Florida, Georgia, and South Carolina, nuclear

plants in other jurisdictions were either (1) legacy projects developed under materially different regulatory paradigms (e.g., traditional cost of service recovery determined through prudence reviews or projects developed by the Tennessee Valley Authority ("TVA"), which sets its own rates and is not subject to subsequent prudence reviews), or (2) jurisdictions without explicit statutory cost recovery frameworks comparable to O. Reg. 53/05. Further, outside of Georgia, South Carolina and Florida, the most recent projects built (2016, Watts Bar 2) or abandoned (1988, Bellefonte) were in Tennessee and developed by TVA, which, as described in Ex. L-C1-EP-016, is not rate regulated.

As discussed in the Concentric report (Ex. C1-1-1 Attachment 1, p. 54-55), however, in a recent report published by the Nuclear Energy Institute ("NEI") titled "State Legislation and Regulations Supporting Nuclear Energy," NEI noted that:

> *Governors, legislators, and regulators play a critical role in shaping policies and regulations that can enhance the development, demonstration, and commercial deployment of a wide array of nuclear technologies. 2024 was another busy year, with states taking pro-nuclear action. In addition, PUCs [public utility commissions] in 7 states approved orders or took direct action in support of nuclear energy.*

Among the incentives provided by U.S. states to support nuclear investment, NEI stated that:

> *Several states have considered advanced cost recovery mechanisms like Construction Work in Progress (CWIP), allowing a utility to collect financing costs for a project before construction is completed. This mechanism reduces the cost to finance a project and may lower the total project costs that eventually are included in the customer rate base.*

b) In Georgia, South Carolina and Florida, the mechanisms analogous to OPG's concurrent cost recovery mechanism allowed for the recovery of financing costs based on the utility's weighted average cost of capital.

c) Yes, OPG's performance with respect to the completion of the DRP was incorporated into Concentric's analysis of risk related to future capital investments. Please see Concentric's response to Energy Probe interrogatory 10 (Ex. L-C1-EP-010).

CCC Interrogatory #030

Interrogatory

Reference:
Exhibit C1, Tab 1, Schedule 1, Attachment 1, pp. 63-64, 103-106

Question(s):

a) Please provide a table that compares the screens applied for the purposes of determining peer group(s) in each of EB-2016-0152, EB-2020-0290 and the current proceeding. As part of the response, please explain the reason for any changes to the screens.

b) Please provide Exhibit 2 in excel format.

c) Please provide a list of companies (and the associated electric operating subsidiaries) that formed the previous peer group in EB-2016-0152 and EB-2020-0290 and are not included in the current proxy group.

d) Please provide a list of companies (and the associated electric operating subsidiaries) that formed the "North American Electric Proxy Group" in EB-2024-0063 and are not included in the current proxy group.

e) For any company that is not included in the current proxy group and was included in any of the EB-2016-0152, EB-2020-0290 or EB-2024-0063 (North American Electric) proxy groups, please provide all the same information as is provided in Exhibits 2 and 4 for these companies (and operating subsidiaries) in excel format.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) The screens used to determine the main peer groups (referred to in the Concentric report as the "Concentric Proxy Group") in the past three proceedings cited in the preamble to the interrogatory (i.e., EB-2016-0152, EB-2020-0290, and the current rate application) are the same. As described in Section 6 of the Concentric report (Ex. C1-1-1, Attachment 1), the screens for the main peer group are:
   - Own regulated generation assets that are included in rate base.
   - Own regulated nuclear and/or hydroelectric generation.
   - Have regulated revenue and regulated net income that make up greater than 60% of total revenue and total income for the consolidated company.

- Have regulated electricity revenue and net income that make up greater than 80% of revenue and income for the consolidated company's regulated operations.
- Have an investment grade credit rating.

In EB-2020-0290, an additional screen to reflect Moody's consideration of OPG's peers per Moody's was used to develop a secondary peer group. In the current proceeding, two additional screens to reflect utilities with a minimum threshold of nuclear and hydroelectric generation were used to develop a subset of the Concentric Proxy Group, and another subset of utilities was screened to narrow the group to jurisdictions that operate in S&P's "most credit supportive" jurisdictions. These peer groups were developed to provide further context on the impact of various characteristics on equity ratio. Alternative or subsets of peer groups were not analyzed in EB-2016-0152.

b) Please see Attachment 1 for the requested data.

c) Please see Attachment 2, which includes the screens that companies in the peer groups in EB-2016-0152 and EB-2020-0290 did not meet based on current data.

d) Please see Attachment 3 for the requested data.

e) Please see Attachment 4 for the requested analysis of Exhibit 2 and Attachment 5 for the requested analysis of Exhibit 4. Note that Attachment 4 is a subset of Attachment 1 containing only the requested companies, except for the addition of El Paso Electric Company. Since El Paso Electric Company is no longer a publicly-traded company, it was excluded from consideration in the Concentric Proxy Group and subgroups.

Energy Probe Interrogatory #004

Interrogatory

Reference:
C1-1-1, Page 1

Preamble:

"In determining the cost of capital, OPG has applied the capital structure of 52% equity and 48% debt. The proposed capital structure is supported by the findings of the Common Equity Ratio Study carried out by Concentric Energy Advisors at Attachment 1 to this exhibit."

Question(s):

a) When did OPG decide to apply to the OEB for approval of the 52% equity and 48% debt capital structure?

b) Considering that Concentrics's report is dated December 2025, was Concentric hired to validate previously made OPG's decision?

c) Did Concentric make any recommendations that OPG did not adopt? If the answer is yes, please list them. If the answer is no, please explain why not.

Response

a) to c)

Concentric was not hired to validate any previously made OPG decisions. All of Concentric's recommendations are as set out in the final report filed at Ex. C1-1-1, Attachment 1. OPG decided to apply to the OEB for approval of its proposed capital structure upon adopting Concentric's recommendations in finalizing its Application (refer to Ex. L-C1-EP-024).

Energy Probe Interrogatory #005

Interrogatory

Reference:
C1-1-1, Page 1

Preamble:

"The OPG expects to receive a shareholder equity injection from the Province of Ontario totaling $5 billion over the 2025-2027 period."

Question(s):

a) Does OPG management believe that the $5 billion equity injection is dependent on OEB approval of the 52% equity and 48% debt capital structure?

b) Did the Province of Ontario indicate to OPG that the current 45% equity 55% debt capital structure is inadequate?

c) Please file any documents including presentations that were exchanged between the Province of Ontario and OPG regarding OPG's capital structure.

Response

a) No. Refer to Ex. L-C1-Staff-022 for further discussion.

b) and c)

OPG declines to provide the requested information on the basis of relevance. This interrogatory seeks information on communications with the Province of Ontario that is not relevant to deciding any issue on the approved Issues List in this application.

Energy Probe Interrogatory #006

Interrogatory

Reference:
C1-1-1, Page 2

Preamble:

Informed by this requirement, the Application seeks approval of the IR term cost of capital presented in Ex. C1-1-1, Tables 13-17 for DNNP LP. In determining the cost of capital on this basis, the Application has applied a 100% equity funded capital structure.

Question(s):

a) Did the Province of Ontario indicate to OPG that DNNP LP capital structure should be 100% equity?

b) Please file any documents including presentations that were exchanged between the Province of Ontario and OPG regarding DNNP LP capital structure.

Response

a) and b)

OPG declines to provide the requested information on the basis of relevance. This interrogatory seeks information on communications with the Province of Ontario that is not relevant to deciding any issue on the approved Issues List in this application.

Energy Probe Interrogatory #007

Interrogatory

Reference:
C1-1-1 Attachment 1, Concentric Report, Page 9

Preamble:

"The FRS, as recently reaffirmed by the OEB in EB-2024-0063, requires that the authorized cost of capital should provide the Company with the opportunity to earn a fair and reasonable return that is:

- Adequate to allow the Company to attract the capital that is necessary to provide safe and reliable service (the "capital attraction" standard).

- Sufficient to ensure the Company's ability to maintain its financial integrity (the "financial integrity" standard); and …"

Question(s):

a) Is Concentric aware of any instances over the past five years when OPG was unable to attract capital that is necessary to provide safe and reliable service?

b) Is Concentric aware of any period over the past five years when OPG was unable to maintain its financial integrity?

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Concentric is not aware of any instances over the past five years in which OPG was unable to attract the capital necessary to provide safe and reliable service. However, the absence of an inability to attract capital does not, in Concentric's view, resolve whether the authorized cost of capital satisfies the capital attraction component of the Fair Return Standard on a prospective basis. The FRS is forward looking and requires that the authorized return, including the equity thickness, provide a reasonable opportunity to attract capital over the period for which rates are set, taking into account expected changes in business, financial, and market conditions. As discussed in Concentric's report, this forward looking assessment is particularly relevant given OPG's increasing forecast capital requirements and evolving risk profile over the upcoming rate period.

b) Concentric is not aware of any period over the past five years in which OPG was unable to maintain its financial integrity. As with capital attraction, however, financial integrity under the FRS is assessed prospectively rather than retrospectively. The fact that OPG has maintained financial integrity in the past does not ensure that it will continue to do so under future conditions if its authorized cost of capital does not appropriately reflect its forward looking risk profile. Accordingly, Concentric's analysis evaluates projected measures of financial integrity, including pro forma credit metrics over the upcoming rate period, to assess whether OPG's deemed capital structure and return parameters are sufficient to support ongoing financial strength from an investor and credit rating perspective.

Energy Probe Interrogatory #008

Interrogatory

Reference:
C1-1-1 Attachment 1, Concentric Report, Page 10

Preamble:

"…(b) expected changes to OPG's risk profile on a forward-looking basis, consistent with how an investor would analyze OPG;"

Question(s):

Does the quoted sentence refer to an investor who is purchasing OPG bonds or OPG shares, or both? Please explain your answer.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

While Concentric's report considers both debt and equity investor viewpoints, the quoted sentence is intended to refer primarily to an equity investor's perspective, consistent with the purpose and focus of Concentric's report.

Concentric's assessment of OPG's forward-looking risk profile is undertaken in the context of evaluating the appropriateness of OPG's deemed equity ratio and return on equity, which necessarily reflects how equity investors would assess changes in business, operational, and regulatory risk over time. As such, the reference to how "an investor would analyze OPG" is meant to reflect the framework and considerations relevant to providers of equity capital, rather than purchasers of OPG debt instruments.

Energy Probe Interrogatory #009

Interrogatory

Reference:
C1-1-1 Attachment 1, Concentric Report, Page 11

Preamble:

"As such, OPG has demonstrated corporate competency in large nuclear refurbishments and will be able to apply lessons learned from the DRP to the PRP."

Question(s):

If OPG has already demonstrated corporate competence with the DRP why would not the subsequent such as PRP have reduced risk? Please explain your answer.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

While the demonstration of corporate competence, all else equal, can mitigate relative risks on future refurbishments, as described in Concentric's report (Ex. C-1-1-1, Attachment 1, p. 11), the PRP is anticipated to cost more than double the cost of the DRP and involves a more aged plant, which leads to increased scope and increases risks related to the discovery of additional scope and challenges during the refurbishment process. In addition, the PRP's schedule, major scope differences, layup period and site location all increase the risk relative to the DRP.

Energy Probe Interrogatory #010

Interrogatory

Reference:
C1-1-1 Attachment 1, Concentric Report, Page 11

Preamble:

"… which leads to increased scope and increases risks related to the discovery of additional scope…"

Question(s):

a) Is Concentric aware of any increases or decreases in DRP scope since its approval by the OEB?

b) Is Concentric concerned that OPG will not be able to manage the risk of additional scope that may be discovered during PRP?

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Concentric is not aware of any material scope increases or decreases to the Darlington Refurbishment Program ("DRP").

However, consistent with Concentric's analysis in its report, the absence of material scope changes does not imply the absence of execution risk. Large, complex nuclear refurbishment projects inherently involve ongoing risk related to emergent conditions identified during execution, even where the overall program scope remains unchanged.

b) No. Concentric's analysis does not suggest that OPG lacks the capability to manage the risks associated with additional scope that may be discovered during the Pickering Refurbishment Program ("PRP").

Rather, from an investor risk perspective, the PRP presents higher inherent execution and scope-discovery risk than the DRP due to factors identified in Concentric's report, including its larger scale, greater complexity, higher forecast cost, overlapping schedules, and the more advanced age and condition of Pickering units.

As Concentric has noted elsewhere in its report, OPG has demonstrated strong organizational competence in executing large nuclear refurbishment projects and has the ability to apply lessons learned from the DRP to the PRP. The identification of higher project risk does not imply an inability to manage that risk; it reflects the reality that certain risks cannot be fully eliminated through experience or mitigation measures and are therefore relevant to the assessment of overall business and financial risk.

Energy Probe Interrogatory #011

Interrogatory

Reference:
C1-1-1 Attachment 1, Concentric Report, Page 12

Preamble:

"…Also at the time of EB-2020-0290, Concentric found that risks to both OPG's prescribed nuclear and hydroelectric operations from severe weather events had increased from EB-2016-0152. Those risks will continue to increase over the course of the coming rate period, …"

Question(s):

a) What is Concentrics's definition of a "severe weather event"?

b) Please confirm that Concentric witnesses are not qualified as weather experts.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Concentric has not adopted a technical or meteorological definition of a "severe weather event." The term is used in a practical sense to refer to weather related events that are materially disruptive to utility operations or infrastructure and therefore relevant to an investor's assessment of business risk. In this context, severe weather events include, for example, flooding, wildfires, ice storms, extreme winds, and other similar events that have the potential to damage assets, interrupt operations, increase operating or capital costs, or lead to additional regulatory or reliability requirements. Concentric's report cites specific examples of such events that have affected OPG's operations in recent years, as discussed on pages 38-39 of Concentric's report (Ex. C1-1-1, Attachment 1).

b) Concentric confirms that its witnesses are not qualified as meteorological or climate science experts. Concentric's assessment of severe weather risk is not intended to provide a technical analysis of weather events, but rather to reflect, from a financial and investor perspective, the observable trend that extreme weather related events have become more frequent and/or more costly for utilities and are increasingly relevant to operating risk, capital planning, and regulatory compliance. This approach is consistent with how such risks are commonly considered by investors

and credit rating agencies when evaluating the overall business risk profile of a regulated utility.

Energy Probe Interrogatory #012

Interrogatory

Reference:
C1-1-1, Attachment 1, Page 12, Concentric Report, Page 11

Preamble:

"The CCR Regulation will not reduce the execution risks of the PRP itself, which, as described above, is larger and more complex than the DRP. Other than the CCR Regulation, Concentrics's analysis finds that OPG's regulatory framework has not changed substantially from a risk perspective since either EB-2016-0152 or EB-2020-0290."

Question(s):

a) Please confirm that CCR Regulation was not intended to reduce execution risk.

b) Which risk will CCR Regulation reduce and by how much?

c) Does OPG's experience with the DRP reduce execution risk? Please explain your answer.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Concentric's understanding of the Government of Ontario's intent with respect to the CCR Regulation is based on the Ontario Minister of Energy and Mines' January 16, 2026 posted decision on amendments to O. Reg. 53/05, which stated that "[t]he amendment to establish a CCR mechanism supports OPG's cash flow needs for DNNP and Pickering Refurbishment Project while the project construction is underway, thereby lowering borrowing requirements and associated costs, which would otherwise make the projects more expensive. This change reduces the long-term project costs to be recovered from ratepayers for these two projects, generating significant overall ratepayer savings over the life of the projects."

b) The CCR mechanism will reduce financial risk relative to what it would otherwise have been. As discussed in Concentric's report, the "CCR Regulation will improve cash flows during the construction phase of the PRP, reducing financial risk during that period relative to what it otherwise would have been." As described in OPG's

evidence (Ex. D2-3-1), OPG included in its application PRP CCR interest amounts on a forecast basis totaling $2,923.3M over the 2027-2031.

c) See the response to Ex. L-C1-EP-010 (b).

Energy Probe Interrogatory #013

Interrogatory

Reference:
C1-1-1, Attachment 1, Page 12, Concentric Report, Page 11

Preamble:

"From a cost recovery perspective, OPG is at risk for variability in output, particularly at its nuclear plants, a factor that distinguishes OPG from other North American regulated generators."

Question(s):

a) How many North American regulated utilities own and operate generators of any type including coal, gas, oil, nuclear, wind, solar, and hydrothermal?

b) Please explain why they are not at risk of variability of output like OPG.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) The statement quoted in the preamble to this interrogatory was made in reference to regulated generators in the proxy groups analyzed by Concentric in this proceeding. Please see the response to Ex. L-C1-CCC-030, and in particular Attachment 1 to that response. As shown in Column F of that Attachment 1, a majority of North American regulated utilities own and operate generation assets. Specifically, 40 North American utility companies listed in that Attachment 1 own generation assets that are included in rate base, and 32 own a substantial amount (defined as greater than 1,000 MW) of regulated generation.

b) Please see the response to Ex. L-C1-CCC-28 (a).

Energy Probe Interrogatory #014

Interrogatory

Reference:
C1-1-1, Attachment 1, Page 12, Concentric Report, Page 11

Preamble:

"In addition, OPG will also experience a significant decline in nuclear generation output, due to the PRP and the permanent shutdown of Units 1 and 4 at Pickering at the end of 2024, which creates additional risk over the upcoming rate period."

Question(s):

Does Concentric believe that purchasers of OPG bonds are not aware of OPG's plans for permanent shutdown of Units 1 and 4 at Pickering?

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

No. The risk described by Concentric in that portion of its report is related to OPG's risk for variability in output, particularly at its nuclear plants. Because of the PRP and the permanent shutdown of Units 1 and 4 at Pickering at the end of 2024, each MWh of nuclear generation will become more financially valuable to OPG as the nuclear generation output that recovers the nuclear revenue requirement is reduced, while at the same time continuing to be more financially valuable, and increasingly so, than each MWh of hydroelectric generation. Concentric believes investors would be aware of that risk.

Energy Probe Interrogatory #015

Interrogatory

Reference:
C1-1-1, Attachment 1, Page 13, Concentric Report, Page 12

Preamble:

"There is evidence, however, as measured by credit spreads, that OPG's access to capital comes at a higher cost than implied by a simple review of its credit rating."

Question(s):

Please provide the link to the evidence mentioned in the quoted text.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

Please see the discussion of OPG's credit spreads provided on pages 50-51 of Concentric's report (Ex. C1-1-1, Attachment 1).

Energy Probe Interrogatory #016

Interrogatory

Reference:
C1-1-1, Attachment 1, Page 14 and Pages 103-109, Concentric Report

Preamble:

"Concentric finds that OPG's risk is significantly elevated relative to the four proxy groups. This is due to OPG's significant nuclear concentration, as well as its status as the only pure generation utility in the group, particularly when combined with the revenue risk it faces related to nuclear output variability. On this latter point, OPG being entirely at risk related to variability in the output of its nuclear facilities distinguishes it from other regulated utilities, as the companies in the proxy group do not face comparable risk."

Question(s):

a) Please confirm that Tennessee Valley Authority (TVA) owns and operates hydroelectric and nuclear generation facilities.

b) Please confirm that TVA is a pure generation utility.

c) Please confirm that TVA is investing in the development of the standard plant design for the GE Vernona BWRX-300 SMR that OPG is building at DNNP.

d) Please confirm that TVA is government owned.

e) What is the authorized equity ratio of TVA?

f) Is TVA at risk of variability in nuclear output?

g) Considering its similarity to OPG, why was TVA not included in the proxy group?

h) Is Concentric aware that WTW included TVA in its comparator organizations (F4-3-1, Attachment 3, Page 5, Comparator Groups, and Page 33 Nuclear Authorized – Executives)?

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Confirmed. Per a February 2026 Tennessee Valley Authority ("TVA") presentation, TVA's total power supply is approximately 10% hydroelectric and approximately 33% nuclear.

b) Not confirmed. TVA's 2025 SEC Form 10-K states that TVA mainly operates a public power system and sells electricity. Approximately 14% of TVA's net plant is transmission assets. TVA also has responsibility to manage the Tennessee River. TVA generates approximately 80% of the power it sells and purchases the remaining 20% from a variety of power producers.

c) Confirmed (see, for example, OPG's 2023 new release "OPG joins international group to advance new nuclear," March 23, 2023).

d) Confirmed. TVA is a wholly-owned U.S. Government corporation. Concentric notes the financial theory and regulatory practice regarding the application of the stand-alone principle, as discussed in Concentric's report. The OEB expressed support for that principle in EB-2024-0063, where it stated "the OEB is firmly of the view that the cost of capital should be determined based on the use of funds and the risk profiles of utilities, rather than their ownership type or capital source."

e) TVA does not have an authorized equity ratio and does not earn a regulated return on equity. TVA's 2025 SEC Form 10-K states that TVA's Board has the sole responsibility for establishing the rates TVA charges for power, and that the rates are not subject to judicial review or to review or approval by any state or other federal regulatory body. Instead of setting rates on a rate base/rate of return methodology, TVA's states that it derives its rates from a debt-service coverage rate methodology, whereby revenues are set to recover TVA's costs plus its debt service obligations plus "[s]uch additional margin as the TVA Board may consider desirable for investment in power system assets, retirement of outstanding Bonds in advance of their maturity, additional reduction of the Power Program Appropriation Investment, and other purposes connected with TVA's power business."

f) TVA is not at risk of variability in nuclear output in the same way that OPG is. If TVA's nuclear facilities are unable to produce power, TVA would replace that power, either from its other facilities or from power purchases. In the near-term, TVA would be at risk for any greater costs associated with such replacement power but would have the ability to flow those cost differences through rates under its debt service coverage model discussed in part e).

g) Concentric disagrees that TVA is similar to OPG from a risk perspective primarily because TVA sets its own rates, and, as such, is not subject to the prudent

investment standard of ratemaking and does not require external approval to change rates.

h) Yes. Willis Towers Watson's ("WTW's") "Total Compensation Benchmarking Study" provided at Ex. F4-3-1 Attachment 3 is a compensation and benefits study (not a cost of capital study) that Concentric understands includes TVA in its "Nuclear Authorized – Executives and Non-Executives" comparator group. The development of a comparator group by WTW for compensation benchmarking, which includes non-utility companies in the aerospace, chemicals, and oil industries, among others, serves a different purpose than the establishment of a proxy group for the purpose of a fair return standard analysis, which is focused not on job functions within the organization but rather on overall business and financial risks, as well as comparability from an investor's perspective.

Energy Probe Interrogatory #017

Interrogatory

Reference:
C1-1-1, Attachment 1, Page 15

Preamble:

"This is somewhat higher than Concentric's recommended equity ratios of no less than 50% in EB-2020-0290 and 49% in EB-2016-0152, reflecting our analysis of current peer group data and Concentric's assessment that OPG's risks have increased since the time of those proceedings."

Question(s):

a) In Concentric's opinion what should OPG do to reduce its risks?

b) Has Concentric ever recommended that any utility's equity ratio be reduced because of reduced risk?

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Concentric's role is to assess the level of business and financial risk faced by the utility and to recommend an appropriate capital structure and return on equity that fairly compensates investors for bearing those risks. In providing a recommendation on equity thickness, Concentric does not opine on utility management decisions or policy choices that would alter the underlying risk profile, nor does it assume that a utility can or should materially alter its risk characteristics as a precondition for earning a reasonable opportunity to recover its cost of capital.

b) In Ontario, Concentric is not aware of any case in which it has recommended a reduction in an approved equity ratio on the basis that a utility's business or financial risk profile had materially declined.

   More generally, Concentric's analytical framework is designed to produce capital structure recommendations to vary where objective evidence demonstrates meaningful differences in relative risk across utilities.

Energy Probe Interrogatory #018

Interrogatory

Reference:
C1-1-1, Attachment 1, Page 36

Preamble:

"Environmental and severe weather risks are impacting utilities globally, resulting in more frequent storm damage and weather-related outages, and increased spending on preparing assets to withstand physical risks."

Question(s):

a) Are all regions of the globe affected equally by severe weather events?

b) Are all regions of Ontario equally affected by severe weather events?

c) Are all utilities equally affected by severe weather events?

d) Do investors believe that OPG faces greater risk from severe weather events than other utilities?

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) No. Severe weather events do not affect all regions of the globe equally. The frequency, severity, and types of weather related risks vary by geography, climate patterns, and local environmental conditions. Concentric's statement is not intended to suggest uniform global exposure, but rather to reflect that extreme and disruptive weather related events are increasing in many regions and are materially affecting utilities' operations, infrastructure planning, and capital spending decisions worldwide. The uncertainty and unpredictability of severe weather events occurring and the increasing prevalence of such events have caused credit rating agencies, equity analysts and investors to consider these risks as they establish their return requirements and decide how to allocate their capital among potential investments.

b) No. Severe weather events do not affect all regions of Ontario equally and Concentric's discussion of environmental and severe weather risk is not predicated

on uniform provincial impacts. Certain regions may be more susceptible to flooding, wildfire risk, ice storms, or extreme winds than others. Concentric's report identifies specific severe weather events that have occurred in the areas of the province in which OPG operates.

c) No. Utilities are not equally affected by severe weather events and Concentric's discussion of environmental and severe weather risk is not predicated on uniform utility impacts. The extent to which severe weather impacts a utility can vary depending on factors such as asset type, generation mix, geographic location, and age of assets. For example, hydroelectric facilities may be more directly exposed to flooding challenges, while transmission dependent or generation only utilities may experience heightened sensitivity to weather related outages and curtailments. Concentric's report identifies specific severe weather events that have impacted OPG's facilities.

d) Concentric's report does not claim that OPG faces greater risk due to severe weather events than other utilities. Concentric's evidence is that the risk associated with severe weather events has increased for OPG as compared to prior payment amount applications. Concentric's assessment reflects an investor oriented evaluation of OPG's overall business risk profile, within which severe weather and environmental risk are one of several relevant contributing factors. These factors influence how investors assess OPG's risk profile relative to other utilities, even if severe weather risks themselves are not uniform across all companies.

Energy Probe Interrogatory #019

Interrogatory

Reference:
C1-1-1, Attachment 1, Pages 39-40

Question(s):

Do investors believe that OPG faces greater cybersecurity risk than other utilities?

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

In its report, Concentric does not conclude that investors believe OPG faces greater cybersecurity risk than other utilities. As discussed on pages 39-40 of Concentric's report (Ex. C1-1-1, Attachment 1), investors recognize that cybersecurity risk has increased across the utility sector as a whole, particularly for owners and operators of critical infrastructure. Utilities, including OPG, are viewed as increasingly exposed to cyber threats. Further, Concentric's assessment reflects that cybersecurity risk has increased for OPG relative to prior payment amount applications, consistent with broader industry trends.

Energy Probe Interrogatory #020

Interrogatory

Reference:
C1-1-1, Attachment 1, Pages 40-44

Question(s):

Is regulatory risk greater in Ontario than in other jurisdictions in North America?

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

No, investors do not perceive regulatory risk in Ontario as greater than in other North American jurisdictions. As discussed on pages 40-44 of Concentric's report (Ex. C1-1-1 Attachment 1), the regulatory environment in Ontario is generally considered credit supportive by credit rating agencies, with S&P ranking Ontario among its "Most Credit Supportive" jurisdictions. On page 42 of Concentric's report, it is noted that the ratings agencies generally point to regulation and OPG's management of regulatory risk as credit positive. At the same time, ratings agencies also consider certain risks related to OPG's pure-play generation operations, which create additional risk for OPG compared to peers, as well as the history of previous regulatory disallowances. For example, S&P comments favorably on incentive ratemaking and Custom IR, while DBRS points to additional profitability pressures from incentive ratemaking and the current hydroelectric rate freeze. The ability of OPG to receive CCR interest during nuclear construction for PRP is also seen as credit positive due to the improved near-term cash flows.

On page 44 of Concentric's report, Concentric explains that due to the risk reducing aspects of regulation, its market/industry Fair Return Standard analysis focused only on companies that are also subject to rate regulation and that Concentric also performed a screen to develop a proxy group of companies that only operate in "Most Credit Supportive" jurisdictions, per S&P. In Section 6 of Concentric's report, Concentric provided a summary of supportive ratemaking structures and mechanisms, such as CCR, that are available to other North American utilities with large nuclear construction programs to provide context for the relative supportiveness of Ontario regulation. In addition, see pages 68-69 and Figure 18 of Concentric's report for a summary of the cost recovery mechanisms that have been implemented by the proxy group companies, and pages 74-76 for information on Concentric's analysis of the "Most Credit Supportive" jurisdictions in North America.

Energy Probe Interrogatory #021

Interrogatory

Reference:
C1-1-1, Attachment 1, Page 45

Preamble:

"Concentric notes that, while credit ratings and borrowing costs provide useful information in an evaluation of the cost of capital, they do not provide a complete picture of equity investor perspectives."

Question(s):

a) Please confirm that Province of Ontario is the only equity investor that OPG has.

b) Does Concentric know what information Province of Ontario uses in its evaluation of the cost of capital of its equity investment in OPG?

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Confirmed.

b) No. Concentric does not have visibility into, nor does it opine on, the Province of Ontario's internal processes, objectives, or information used in assessing the cost of capital associated with its equity investment in OPG.

Concentric's evidence reflects an independent assessment of the cost of capital from the perspective of capital markets and the Fair Return Standard applied in regulated proceedings, and is not intended to replicate or infer the Province of Ontario's internal investment evaluation framework.

Further, Concentric notes the financial theory and regulatory practice regarding the application of the stand-alone principle, as discussed in Concentric's report. The OEB expressed support for that principle in EB-2024-0063, where it stated "the OEB is firmly of the view that the cost of capital should be determined based on the use of funds and the risk profiles of utilities, rather than their ownership type or capital source."

Energy Probe Interrogatory #022

Interrogatory

Reference:
C1-1-1, Attachment 1, Pages 49-50

Preamble:

"This indicates that, all else equal, a 45% equity ratio is not sufficient to maintain OPG's key credit metrics within the range required for its current ratings. Conversely, at a 52% equity thickness, and all else equal, OPG's regulated-only metrics will consistently be above the downgrade thresholds, indicating that, based on that measure, a 52% equity ratio will support the stand-alone financial integrity and credit strength of the Company's regulated business."

Question(s):

Is Concentric claiming that OPG's cost of debt would increase if the equity ratio remained at 45%? If the answer is yes, please provide an estimate of the increase in percent interest and in dollars.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

No. Concentric is not claiming that OPG's cost of debt would necessarily increase by a specific, quantifiable amount if the equity ratio remained at 45%, nor is Concentric providing an estimate of a particular increase in interest rates or debt expense. The statement cited in the preamble reflects a credit metric based, forward looking assessment of financial integrity, not a prediction of near term borrowing costs. Concentric's analysis demonstrates that, on a regulated only, pro forma basis and all else equal, a 45% equity ratio results in projected credit metrics that fall below thresholds supporting OPG's current credit ratings, whereas a 52% equity ratio results in metrics that are consistently above those downgrade thresholds. This analysis is intended to assess the risk of rating pressure and the sufficiency of equity thickness to support financial integrity, rather than to quantify a specific change in borrowing costs. While credit ratings are an important determinant of debt costs, the relationship between credit metrics, ratings outcomes, and borrowing rates is influenced by many factors. Actual debt costs depend on a range of factors, including market conditions at issuance, investor demand, issuance timing, and broader macroeconomic conditions.

As such, Concentric did not attempt to estimate a specific increase in interest rates or an associated dollar impact.

Energy Probe Interrogatory #023

Interrogatory

Reference:
C1-1-1, Attachment 1, Page 68 and A1-3-1, Page 3

Preamble:

"While not the same as OPG's regulatory mechanisms, these mechanisms are similar in their function of reducing regulatory risk and improving cash flow consistency, which are the key items investors look to when comparing utility profiles."

Question(s):

a) Would the proposed custom incentive rate-setting ("Custom IR") reduce regulatory risk of OPG?

b) Do any utilities in the proxy group have similar Custom IR rate setting mechanisms? If the answer is yes, please list the utilities and describe the Custom IR of each one.

c) Does the creation of DNNP SPV reduce the regulatory risk of OPG?

d) Do any utilities in the proxy group have similar SPVs for major nuclear projects? If the answer is yes, please list them and describe each one

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) The proposed Custom IR framework would not, on its own, materially reduce the regulatory risk related to OPG's nuclear and hydroelectric businesses relative to the regulatory frameworks that have applied to OPG in recent proceedings. As discussed in Concentric's report, the proposed Custom IR is structurally similar to incentive rate-setting approaches previously approved by the OEB for OPG, including the use of a forecast test year and a multi-year rate term. As such, investors would not view the proposed Custom IR as a fundamental change in regulatory risk when compared to prior Custom IR applicable to OPG.

b) Yes. Several utilities within the proxy group companies operate under multi-year incentive or forward test-year-based rate-setting frameworks that are similar in function to OPG's Custom IR proposals for its nuclear and hydroelectric

businesses. These frameworks typically involve an initial cost-of-service determination followed by indexed or formulaic adjustments over a defined rate term. Such mechanisms are common across North American jurisdictions. See Attachment 1 (and in particular, Table A-6) for a list of those utilities.

c) Concentric's equity ratio analysis and recommendation focused on OPG's prescribed nuclear and hydro-electric facilities. As indicated on page 9 of Concentric's report, Concentric did not consider the creation of the DNNP SPV in its analysis or recommendation.

d) Concentric did not perform this research as part of its equity ratio report for OPG.

Energy Probe Interrogatory #024

Interrogatory

Reference:
C1-1-1, Attachment 2, Page 2

Preamble:

"... discuss the findings and preliminary results of the Study with Torys and OPG on a date to be agreed upon (the "Discussion of Findings"), which shall be no later than June 2, 2025, unless otherwise agreed to by the parties;"

Question(s):

a) When did the discussion of the findings and preliminary results take place?

b) Did Concentric provide OPG with any documents or presentations of its preliminary findings? If the answer is yes, please file them. If the answer is no, please explain why not.

Response

a) and b)

The timing of the discussion of preliminary results is not relevant. Concentric did not provide OPG with a written document or presentation in this regard. Further, even if there was such a document (a draft of preliminary results), it would be irrelevant and privileged. The Application relies on Concentric's final report, setting out its scope of work, findings and opinions, which is what provides probative value for the OEB. The final report from Concentric has been filed with the Application at Ex. C1-1-1, Attachment 1.

Energy Probe Interrogatory #025

Interrogatory

Reference:
C1-1-1, Attachment 3, Page 1

Question(s):

Considering that the Polar Star evidence was filed on December 5, 2025, was Polar Star hired to validate previously made DNNP financing decisions?

Response

The Applicants interpret “DNNP financing decisions” in the context of the question to mean decisions for DNNP LP not to obtain non-recourse investment grade financing within 12-18 months of the in-service date of DNNP Unit 1. The Applicants had not previously made any such decisions.

Energy Probe Interrogatory #026

Interrogatory

Reference:
C1-1-1, Attachment 3, Page 6

Preamble:

"From an investor's perspective, there are numerous risks associated with newly in-service nuclear projects and particularly those that utilize first of a kind ("FOAK") technology. I reviewed ten key risks that I consider would be of importance for debt investors. These risks may be mitigated to the extent possible by the experts at OPG, but in my opinion institutional investors will be very cautious in accepting FOAK nuclear technology risk and the related operating risk."

Question(s):

a) Is Polar Star aware that the Darlington Refurbishment Program (DRP) was presented to the OEB as a FOAK (EB-2016-0152 Exhibit D2-2-8, Attachment 2)?

b) Is Polar Star aware of any difficulties in the financing of the DRP?

Response

This response was prepared by Polar Star Advisory Services ("Polar Star")

a)

i) I was aware that the Darlington reactors utilized the familiar and well proven CANDU technology for the operation of the reactors, but I was not specifically aware that the DRP had several FOAK aspects (e.g., tooling, worker training and component extraction techniques) related to the refurbishment process itself.

However, the refurbished CANDU reactors themselves did not involve FOAK technology but utilized the same fundamental design and operating principles as they did prior to refurbishment (i.e., they had a proven successful operating history). This contrasts with the DNNP which involves finalizing the development of a brand-new, GE-Hitachi BWRX-300 design that has never previously operated on a commercial basis in a G7 country.

ii) Additionally, DRP's situation is not an appropriate precedent for DNNP LP because:
   1. The Darlington Refurbishment Project was a phased project. There were always some reactors in normal operating mode generating cash flow that could be used to service debt. This is not the case with Unit #1 of DNNP. If the first DNNP Unit is not operating, there is zero cash flow that is generated to service debt.
   2. The Darlington Refurbishment Project was 100% owned and financed by OPG. This meant that if the particular units being refurbished could not be successfully put back into operation, OPG's bondholders would not have been impacted unless OPG could not service the bonds using proceeds from all its remaining operations. This is not the case for the DNNP SMR unit(s) that will be owned by DNNP LP and where non-recourse financing is being sought (i.e., without the benefit of recourse to other OPG assets and cashflows).

b) No, I am not aware that OPG had any difficulties financing the wholly owned DRP.

Energy Probe Interrogatory #027

Interrogatory

Reference:
C1-1-1, Attachment 3, Page 33

Question(s):

Did OPG agree with all of Polar Star's opinions? Please explain your answer.

Response

The Applicants are not aware of all of Polar Star's opinions. With respect to Polar Star's report in Ex. C1-1-1, Attachment 3, the Applicants agree with Polar Star's opinion on p. 34 that "there is a low to very low probability of a successful offering of investment grade non-recourse bonds within 12-18 months following the in-service date of the first SMR unit for the DNNP." In addition to relying on Polar Star's opinion in this regard, as noted in Ex. L-C1-SEC-038, OPG received similar feedback through discussions with its investment banking advisors.

Minogi Corp Interrogatory #002

Interrogatory

Reference:

- **Exhibit C1, Tab 1, Schedule 1**

Question(s):

a) Please confirm whether OPG has considered external equity participation including participation by First Nations, as an alternative or complementary source of capital for future generation included in the Application.

b) If yes to a), describe the extent to which such participation could:
   (i) reduce reliance on ratepayer funded capital;
   (ii) diversify sources of financing; and
   (iii) affect OPG's capital structure.

c) If no to a), please explain why such participation has not been considered as part of OPG's capital planning and cost of capital determination.

Response

Refer to Ex. L-A2-Staff-016, part c).

SEC Interrogatory #029

Interrogatory

Reference:
C1-1-1, Attachment 1

Question(s):

With respect to the Concentric Energy Advisors ("Concentric"), *Common Equity Ratio Study*, for each proceeding where the authors of the Concentric report have provided expert evidence on utility cost of capital, please provide the following information regarding those proceedings, as applicable:

a) Jurisdiction
b) Date
c) Docket Number
d) Applicant
e) Client
f) Existing equity ratio
g) Author's recommended equity ratio
h) Approved equity ratio as a result of the proceeding, and how it was reached (decision or settlement)
i) Existing ROE
j) Author's recommended ROE as a result of the proceeding, and how it was reached (decision or settlement)
k) Approved ROE
l) A copy or web link to the authors written report/testimony
m) A copy or web link to the commission/regulatory decision

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

Please see Attachment 1 for the requested information. Concentric has provided the information requested in parts (a) through (l) for all of Mr. Dane's expert evidence on utility cost of capital filed since 2011, except for the information in parts (f) and (i), which Concentric does not track, except where that information was known in Ontario. Because all of these cases are a matter of public record, the information requested in parts (l) and (m) can be found on the websites of the respective Boards and Commissions.

SEC Interrogatory #030

Interrogatory

Reference:
C1-1-1, Attachment 1

Question(s):

With respect to the Concentric Energy Advisors ("Concentric"), *Common Equity Ratio Study:*

a) Please provide the most recent S&P, DBRS, Moody's and Fitch rating reports, for each of the peer/proxy group companies.

b) Please include the full documents included in the following footnotes: 70, 72, 83, 105, 146, and 171-182.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Please see Attachments 1 through 18 (Confidential) for the requested S&P reports for each of the 18 peer/proxy group companies. Concentric does not have access to reports from DBRS, Moody's, and Fitch for the peer companies, which require purchase or a subscription.

b) Please see Attachments 19 through 35 (Confidential) for the source documents cited in the referenced footnotes.

Exhibit L-C1-SEC-030, Attachment 1

S&P Global Ratings
Algonquin Power & Utilities Corp.

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 2

S&P Global Ratings
ALLETE Inc.

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 3

S&P Global Ratings
Ameren Corp.

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Exhibit L-C1-SEC-030, Attachment 4

S&P Global Ratings
American Electric Power Co. Inc.

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Exhibit L-C1-SEC-030, Attachment 5

S&P Global Ratings
Dominion Energy Inc.

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Exhibit L-C1-SEC-030, Attachment 6

S&P Global Ratings
Duke Energy Corp.

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Exhibit L-C1-SEC-030, Attachment 7

S&P Global Ratings
Edison International

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 8

S&P Global Ratings
Emera Inc.

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Exhibit L-C1-SEC-030, Attachment 9

S&P Global Ratings
Entergy Corp.

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Exhibit L-C1-SEC-030, Attachment 10

S&P Global Ratings
Evergy Inc.

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Exhibit L-C1-SEC-030, Attachment 11

S&P Global Ratings
Fortis Inc.

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 12

S&P Global Ratings
IDACORP Inc.

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 13

S&P Global Ratings
NextEra Energy Inc.

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 14

S&P Global Ratings
Pinnacle West Capital Corp.

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 15

S&P Global Ratings
PNM Resources Inc.

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 16

S&P Global Ratings
Portland General Electric Co.

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Exhibit L-C1-SEC-030, Attachment 17

S&P Global Ratings
Southern Co.

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Exhibit L-C1-SEC-030, Attachment 18

S&P Global Ratings
Xcel Energy Inc.

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 19

S&P Global Ratings
Criteria
Corporates Utilities: Key Credit Factors For The Regulated Utilities Industry

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 20

Moody's Ratings
Rating Methodology Regulated Electric and Gas Utilities

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 21

S&P Global Ratings
Ontario Power Generation Inc.

This Attachment was filed as confidential information in its entirety.

STATUS REPORT

State Legislation and Regulations Supporting Nuclear Energy

January 2025

NEI NUCLEAR ENERGY INSTITUTE

INTRODUCTION

Governors, legislators, and regulators play a critical role in shaping policies and regulations that can enhance the development, demonstration, and commercial deployment of a wide array of nuclear technologies. 2024 was another busy year, with 25 states taking pro-nuclear action. In addition, PUCs in 7 states approved orders or took direct action in support of nuclear energy. Announcements of partnerships between tech companies and nuclear underscores the technology sector's increasing confidence in nuclear as a key solution for their long-term needs.

As state officials consider measures that address the changing energy mix, the Nuclear Energy Institute has produced this compendium providing a state-by-state overview of legislation, executive orders, and regulations that have supported nuclear energy since the early 2000s.

RECENT POLICY TRENDS

Task Forces, Commissions, Studies and State Energy Plans

- **Task forces and commissions:** Ohio, Kentucky, Michigan, New Hampshire, Tennessee and Texas have established task forces or commissions that bring together various stakeholders, including government officials, academia, industry and others, to explore policy options to maintain existing nuclear facilities and support advanced reactor technologies.
    - Recommendations include ideas such as legislative measures on workforce centralizing nuclear in a nuclear agency and state financing for early site permitting.

- **Studies:** Several states have requested studies exploring the potential economic impacts, job creation, and electricity customer cost savings related to siting and permitting new reactor technologies, including projects converting decommissioned coal sites to nuclear power.
    - Requested: Colorado and Florida
    - Published: Connecticut, Indiana, Kentucky, Louisiana, Maryland, Montana, Michigan, Nebraska, New Hampshire, Pennsylvania, Tennessee, and Texas

- **State energy plans:** Some Governors and state agencies have developed long-term plans to reach decarbonization goals that include nuclear energy.

Financing and Tax Incentives

- **Tax exemptions:** Some states have passed laws allowing for certain tax exemptions on property and sales of electricity and for new capital investments associated with new reactor development.

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- **Advanced cost recovery:** Several states have considered advanced cost recovery mechanisms like Construction Work in Progress (CWIP), allowing a utility to collect financing costs for a project before construction is completed. This mechanism reduces the cost to finance a project and may lower the total project costs that eventually are included in the customer rate base.

- **Supply chain:** The nuclear energy supply chain is complex and spans the globe. A reliable supply chain and manufacturing base create efficiencies that reduce the cost and timeline to build new reactors.

- **Workforce development:** Operating reactors today employ between 500 and 800 people in permanent jobs. The nuclear sector is one of the most skilled industries and requires numerous different highly technical certifications. The workforce is sustained by a robust investment in nuclear-energy programs at our nation's universities and trade schools. Several states have begun evaluating university, community college, and trade school curriculum and training programs to ensure the curriculum supports jobs that enable the construction and operation of the next generation of nuclear plants.

Valuing Carbon-Free Electricity Generation

- **Zero-emission credit programs:** Several states have adopted legislation or regulations that provide a payment at a set rate for every megawatt-hour of carbon-free electricity generation.

- **Clean energy standards:** Many states have renewable portfolio standards that require utilities to sell a specified amount of renewable energy. Some states are now looking to expand these requirements and modify the definition to include a broader scope of clean energy resources. Nuclear generation is often included in the expanded definition of clean energy resources because of the important role that it plays in an affordable, reliable, low-carbon energy system.

- **Market-based carbon pricing mechanisms:** As many states look to decarbonize the energy sector, there is a growing interest in regional greenhouse gas emission reduction programs, a carbon tax, or cap-and-trade programs that take advantage of the carbon-free benefits of nuclear power.

Removing Prohibitions

- **Repealing laws prohibiting nuclear development:** Some states have historically had specific restrictions on the construction of new nuclear power facilities. However, several states have recently removed these prohibitions to support potential new reactor development.

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Increasing State Regulatory Responsibility

- **Signaling Support:** Several state Public Service Commissions (PSC) have taken action this year in support of new or existing nuclear.
  - In response to state legislation, the Indiana Utility Regulatory Commission adopted regulations this year for advanced reactors, while the Kentucky PSC has started the process of developing new regulations.
  - In Mississippi, the PSC adopted a resolution expressing support for new and existing nuclear.
  - In Louisiana, the PSC launched the Louisiana Advanced Competitive Edge (LANCE) project, which included a two-day meeting on deploying new nuclear in the state as well as a draft report of recommendations for the PSC and other state officials to consider.
  - More often, state PSCs are being asked to consider new nuclear in utility integrated resource plans. This year, the North Carolina Utilities Commission issued an order approving Duke's NC plan, which includes funding for early development costs, targeting 300 MW of advanced nuclear capacity online by 2034 and 600 MW by 2035.

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ALABAMA

Legislation: H.R. 84
Adopted March 2017

Encourages ongoing bipartisan efforts to spur the development of advanced nuclear reactors and innovative nuclear technologies.

ALASKA

Legislation: S.B. 177/H.B. 299
Enacted May 2022

Reduces barriers to the deployment of microreactors in remote communities.

Legislation: S.B. 220
Enacted July 2010

Establishes a statewide energy policy and levels the playing field for nuclear energy projects so that they can be considered alongside other energy sources. Allows small-scale nuclear reactor developers to apply for funding from the state's Power Project fund.

ARIZONA

Resolution: Senate Concurrent Resolution 1010
Adopted April 2017

Recognizes that the Members of the Legislature support the use of nuclear energy as a safe and efficient means of energy production and express their commitment to the continuing and safe use of nuclear energy to supply the energy consumption needs of the people of Arizona.

Legislation: Senate Concurrent Memorial 1004
Adopted September 2012

Recognizes benefits of partnering with federal government and private industry to develop spent fuel reprocessing and storage sites.

ARKANSAS

Legislation: H.B.1142
Enacted March 2023

Establishes the Arkansas Nuclear Recycling Program under the Division of Environmental Quality (DEQ).

Resolution: House Concurrent Resolution 1015
Adopted May 2019

Supports study of the commercial application of existing technology to reclaim and repurpose spent nuclear fuel rods.

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Legislation: S.B. 246
Enacted 2013

Establishes a committee to report on the future of Arkansas' energy needs, including the potential for new nuclear facilities.

CALIFORNIA

Regulation: A.24-03-18
Ordered December 2024

The California Public Utilities Commission approved $722.6 million in ratepayer costs to cover the continued operation of the Diablo Canyon Power Plant.

Resolution: Assembly Joint Resolution 18
Adopted August 2024

Urges the Congress of the United States to prioritize its obligation to provide a home for spent nuclear fuel and to implement revisions to the federal Nuclear Waste Policy Act of 1982.

Legislation: S.B. 108
Enacted June 2024

Allows the Director of Finance to transfer up to $400,000,000 as a loan to the Diablo Canyon Extension Fund from the General Fund for the purpose of extending operations of Diablo Canyon powerplant, to dates that will be no later than November 1, 2029, for Unit 1, and no later than November 1, 2030, for Unit 2.

Regulation: Rulemaking 23-01-077
Ordered December 2023

The decision directs and authorizes extended operations at Diablo Canyon Nuclear Power Plant until October 31, 2029 (Unit 1) and October 31, 2030 (Unit 2). The approval is subject to the following conditions: 1. The NRC continues to authorize operations; 2. The $1.4 billion loan agreement authorized by S.B. 846 is not terminated; and 3. The Commission does not make a future determination that extended operations are imprudent or unreasonable.

Legislation: S.B. 846
Enacted September 2022

Authorizes the state to provide a $1.4 billion loan guarantee to the Diablo Canyon Nuclear Power Plant in order to extend plant operations through 2030.

COLORADO

Legislation: H.B. 23-1247
Enacted August 2023

Provides $50,000 to the director of Colorado's energy office to conduct studies of electric transmission and advanced energy solutions technologies including advanced nuclear in rural Colorado.

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Legislation: S.B. 18-003
Enacted June 2018

Requires the Colorado Energy Office to work with communities, utilities, private and public organizations, and individuals to promote cleaner energy sources such as nuclear energy, alongside biogas and biomass.

CONNECTICUT

Feasibility Study
Released February 2024

Link to final report.

Legislation: S.B. 385
Enacted May 2024

Permits the Commissioner of Energy and Environmental Protection to coordinate with other New England states to procure generation resources from a nuclear power generating facility for ten years following the end of existing agreements with a nuclear power generating facility.

Legislation: S.B. 7
Enacted July 2023

Expands the definition of Class I renewable energy sources to include Nuclear generating facilities built after October 1, 2023; establishes the Connecticut Council for Advancing Nuclear Energy Development; and requires the Department of Energy and Environmental Protection (DEEP) to study the feasibility of deploying small modular reactors, advanced nuclear reactors, fusion energy facilities, and other zero carbon resources.

Legislation: H.B. 5202
Enacted May 2022

Partially repeals the state's nuclear moratorium to allow for advanced reactor deployment within the footprint of existing nuclear facilities.

Legislation: H.B. 1501
Enacted October 2017

Allows for the Millstone nuclear power plant to participate in the state's zero-carbon procurement program.

Executive Order: No. 59
Signed 2017

Requires the state to study the economic viability of the Millstone nuclear generating facility.

FLORIDA

Legislation: H.B. 1645
Enacted May 2024

Requires the public service commission to evaluate feasibility of using advanced nuclear power technologies.

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Legislation: H.B. 7109
Enacted June 2015

Authorizes electric utilities to petition the Florida Public Service Commission for financing orders that authorize the issuance of nuclear asset recovery bonds.

Legislation: S.B. 1472
Enacted June 2013

Amends existing Florida law for certain cost recovery related to the siting, design, licensing, and construction of nuclear and integrated gasification combined cycle power plants.

Legislation: H.B. 7135
Enacted June 2008

Permits cost recovery for transmission lines for new nuclear power plants and establishes greenhouse gas reduction targets.

Legislation: S.B. 888
Enacted June 2006

Supports the construction of new nuclear plants through several provisions including: exempting new nuclear plants from the mandatory competitive bidding process and instructing the Public Service Commission to establish alternative cost recovery mechanisms.

GEORGIA

Regulation: Docket No. 29849 Georgia Public Service Commission
Ordered December 2023

Unanimously approves Georgia Power's application to adjust rates to include reasonable and prudent costs from Plant Vogtle Units 3 and 4.

Regulation: Docket No. 27800 Georgia Public Service Commission
Ordered March 2009

Approves a utility request to proceed with the construction of two new generating units at Vogtle and to seek recovery of financing costs from ratepayers; state law requires the company to obtain such a certification.

Legislation: S.B. 31
Enacted April 2009

Allows a utility to recover from its customers the costs of financing associated with the construction of a nuclear plant that has been certified by the Georgia Public Service Commission.

IDAHO

Resolution: Senate Concurrent Resolution 113
Adopted March 2024

Highlights the Legislature's strong support for the historical, current, and future regional impacts of Idaho National Laboratory and recognizes the potential of the newly formed Idaho Advanced Energy Consortium.

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Legislation: H.B. 96
Enacted July 2023

Expands the definition of clean energy to include nuclear, hydrogen, energy/battery storage, and other non-carbon emitting resources.

Executive Order: No. 2018-07
Signed June 2018

Supports the continued promotion, advancement and deployment of advanced reactor technologies, including small modular reactors, in Idaho.

Legislation: H.B. 591
Enacted March 2018

Allows for tax exemptions for research and development opportunities associated with small modular reactors.

Executive Order: No. 2012-01
Signed February 2012

Establishes the Leadership in Nuclear Energy (LINE) Commission tasked with making recommendations to the Governor on policies and actions the state of Idaho can take to support and enhance the long-term viability and mission of the Idaho National Laboratory and the broader nuclear industry in the state.

Legislation: S.B. 1123
Enacted April 2009

Recognizes that utilities are embarking on major transmission and generation projects to serve growing loads during a period when financial markets are risk-averse and is designed to provide the stability necessary to attract investors at a more reasonable cost-of-capital.

ILLINOIS

Legislation: H.B. 2473
Enacted December 2023

Repeals the moratorium on new construction, allowing for the construction of advanced nuclear reactors 300MW or smaller beginning in 2026, and authorizes the Governor to establish a commission to study the potential for development of SMRs in the state.

Legislation: S.B. 18
Enacted September 2021

Establishes a zero-emission credit program for the Byron, Dresden, and Braidwood nuclear facilities within the state.

Legislation: S.B. 2814
Enacted December 2016

Establishes a zero-emission credit program for the Clinton and Quad Cities nuclear facilities within the state.

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Resolution: House Resolution 1146
Adopted May 2014

Supports the state's existing nuclear fleet and urges the federal government and the Midwest grid operator to adopt policies and rules to protect Illinois's nuclear plants for the sake of the environment, the economy, and energy reliability.

INDIANA

Feasibility Study
Released November 2024

Purdue University publishes comprehensive analysis of SMR applications and their impacts for the state of Indiana. Study was conducted at the request of Indiana Office of Energy Development. Link to report.

Regulation: Docket 170 IAC 4-11 Indiana Regulatory Utility Commission
Released June 2023; Ordered May 2024

Adopts requirements granting the certification for the construction, purchase, or lease of small modular reactors by a public utility.

Legislation: H.B. 1278
Enacted March 2024

A business is no longer required to file a monthly report to the lieutenant governor after purchasing a nuclear generating facility the previous month.

Legislation: S.B. 176
Enacted April 2023

Changes the rated electric generating capacity from 350 megawatts to 470 megawatts for purposes of the definition of "small modular nuclear reactor" as used in the statutes concerning: (1) certificates of public convenience and necessity issued by the Indiana utility regulatory commission for the construction, lease, or purchase of electric generation facilities; and (2) financial incentives for energy utilities that invest in clean energy projects.

Legislation: H.B. 1421
Enacted March 2023

Requires the Indiana utility regulatory commission (IURC) to issue an order granting or denying an application for a certificate of public convenience and necessity (certificate) not later than 240 days after the filing of the application and the submission of the applicant's case in chief.

Legislation: S.B. 271
Enacted March 2022

Requires the Indiana Utility Regulatory Commission to adopt rules concerning the granting of certificates for the construction, purchase, or lease of small modular nuclear reactors.

Resolution: House Resolution 54
Adopted March 2013

Urges a study on small modular reactors that includes economic issues such as cost, economic impact, potential job creation, and cost savings for electricity consumers, as well as technical, design, and regulatory questions.

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Legislation: S.B. 251
Enacted May 2011

Provides financial incentives to assist electric companies with nuclear generating facilities to recover costs and expenses incurred during comprehensive life cycle management upgrades to existing facilities.

IOWA

Legislation: H.F. 2279
Enacted May 2024

Amends Code 2024 to include electric storage unit and nuclear.

Legislation: H.F. 2399
Enacted April 2010

Requires certain Iowa utilities to analyze and prepare for the possible construction of new nuclear generating facilities and encourages utilities to perform studies on expanding nuclear power in the state, at limited cost to ratepayers and with oversight of the Iowa Utilities Board.

Legislation: H.F. 577
Enacted 2001

Specifies that rate-making principles will apply when a new baseload generating facility (built or leased) begins service before construction commences or a lease is signed.

KANSAS

Legislation: S.B. 410
Enacted April 2024

Exempts new nuclear facilities from certain property taxes.

Legislation: S.B. 586
Enacted May 2008

Allows power plants to qualify for recovery of Construction Work in Progress (CWIP) and other preconstruction expenditures in rates.

Legislation: H.B. 2038
Enacted April 2007

Exempts from state property taxes any property purchased, constructed or installed to expand capacity at an existing nuclear plant or to build a new nuclear plant.

Legislation: Substitute for H.B. 2516
Enacted April 2004

Allows the Kansas Corporation Commission (KCC) to make adjustments to a utility's revenue requirements allowing the utility to retain benefits equivalent to 10 percent of the net revenue from electricity sold to out-of-state customers generated from a new or expanded generator in a county with 5 percent or less population growth.

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Legislation: Substitute for S.B. 104
Enacted April 2003

Permits the Kansas Corporation Commission to determine rate-making principles that will apply to a utility's investment in generation or transmission before constructing a facility or entering into a contract for purchasing power.

KENTUCKY

Resolution: Senate Joint Resolution 140
Adopted April 2024

Instructs the Public Service Commission to prepare and streamline its processes to be able to immediately assist with any nuclear siting or construction applications that might be filed with the commission.

Resolution: Senate Resolution 327
Adopted April 2024

Urges Congress to enact legislation to reform federal permitting and environmental review processes to expedite the deployment of modern energy infrastructure (including nuclear).

Legislation: S.B. 198
Enacted April 2024

Establishes the Kentucky Nuclear Energy Development Authority. The Authority will conduct a study to identify the workforce needed to develop and support the nuclear ecosystem.

Legislation: H.B. 1
Enacted April 2024

Appropriates $20 million for fiscal year 2025 to the University of Kentucky budget unit to support and facilitate the development of nuclear energy by the Center for Applied Energy Research.

Resolution: House Resolution 70
Adopted February 2024

Urges Congress to enact legislation to reform federal permitting and environmental review processes to expedite the deployment of modern energy infrastructure (including nuclear).

Resolution: Senate Joint Resolution 79
Adopted March 2023

Establishes the Nuclear Energy Development Working Group, which is tasked with identifying the barriers to the deployment of nuclear power generation and related technologies and to consult with stakeholders to develop recommendations for the role of a permanent nuclear energy commission to be established in state government. Final Nuclear Energy Working Group Report

Legislation: S.B. 11
Enacted June 2017

Removes the moratorium on the construction of new nuclear facilities within the state.

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Legislation: H.B. 559
Enacted April 2012

Allows for the construction of facilities that use certain nuclear technologies including the enrichment of depleted uranium hexafluoride tails, processing of metals contaminated with radioactive materials, recycling or reprocessing of spent fuel, and nuclear-assisted coal or gas conversion processes.

LOUISIANA

Executive Order: Executive Order 166
Enacted November 2024

The order requires the Secretary of Environmental Quality to review the Department's regulatory procedures to improve permitting and licensing timelines. The Secretary is required to develop and adopt procedures that would support and advance methods to resolve environmental hazards and prepare for the expansion of nuclear energy. Recommendation due July 1, 2025.

Draft Report: Docket No. X-36987 Louisiana Public Service Commission
Released October 2024

The draft Louisiana Advanced Competitive Edge (LANCE) Framework was filed into the docket. The Framework includes recommendations to the Commission to support the deployment of advanced reactors.

Regulation: Docket No. X-36987 Louisiana Public Service Commission
Effective June 2024

The Commission launched the Louisiana Advanced Nuclear Competitive Edge (LANCE) project. Brings together state and federal government, business and industry, electric utilities, manufacturers, educational institutions, and others who want to help chart a path for energy driven economic opportunity that utilizes advanced nuclear as a catalyst.

Resolution: House Resolution 2
Adopted May 2024

Urges Congress to enact legislation to reform federal permitting and environmental review processes to expedite the deployment of modern energy infrastructure (including nuclear).

Regulation: Docket No. X-36987 Louisiana Public Service Commission
Effective September 2023

The Commission has opened a docket to study and track the development of advanced reactors in the state.

Regulation: Docket No. R-29712 Louisiana Public Service Commission
Ordered May 2007

Allows for a phased cost recovery mechanism on construction work in progress for nuclear facilities.

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MARYLAND

Legislation: S.B. 528

Enacted April 2022

Establishes greenhouse gas emission reduction targets and recognizes the critical role that nuclear power plays in the state's clean energy generation profile.

Regulation: Case No. 9127 Maryland Public Service Commission

Ordered June 2009

Grants a Certificate of Public Convenience and Necessity to construct a new reactor at the Calvert Cliffs facility in Calvert County.

MASSACHUSETTS

Legislation: S 2967

Enacted November 2024

Modifies definition of "clean energy" and "clean energy research" to include nuclear fission. And allows the Commonwealth to purchase nuclear energy.

MICHIGAN

Legislation: S.B. 747

Enacted July 2024

Includes as part of the state's 2024-2025 budget, $150 million to support efforts to reopen the Palisades power plant.

Feasibility Study

Released March 2024

In accordance with H.B. 6019 of 2022, the Public Service Commission submitted the Nuclear Feasibility Study Report to the Governor and Legislature.

Legislation: S.B. 271

Enacted November 2023

Requires a clean energy portfolio for Michigan and includes nuclear energy generation as part of the state's clean energy definition. Renewable Energy targets of 15% through 2029, 50% by 2030 and 60% by 2035.

Legislation: H.B. 4437

Enacted July 2023

Includes as part of the state's 2023-2024 budget, $150 million to support efforts to reopen the Palisades power plant.

Legislature Launches Bipartisan Nuclear Energy Caucus

2023 Legislative Session

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Regulation: Case No. U-21358 Michigan Public Service Commission

Effective March 24, 2023

Following the 2022 legislation, the Commission established a Nuclear Feasibility Study Workgroup and hired a firm to draft a study examining the potential for advanced reactors in the state. The study was due back to the Commission in March 2023 and will be transmitted to the legislature in April 2024.

Legislation: H.B. 6019

Enacted October 2022

Directs the Michigan Public Service Commission to engage an outside consulting firm to examine the feasibility of nuclear power generation in the state.

Resolution: Senate Concurrent Resolution 8

Last Adopted April 2017 (duplicate resolutions passed previously)

Urges the federal government to fulfill its obligation to establish a permanent solution for handling high-level nuclear waste.

Legislation: H.B. 5524

Enacted October 2008

Creates a certificate of necessity for large capital investments, including the construction of nuclear plants.

MINNESOTA

Legislation: H.F. 7/S.F. 4

Enacted February 2023

All utilities must provide Minnesota customers with 100 percent carbon-free electricity by 2040. The state's definition of carbon-free energy includes all carbon-free generation sources.

MISSISSIPPI

Resolution: Mississippi Public Service Commission

Adopted March 2024

The Public Service Commission adopted a resolution expressing its support of nuclear energy as a clean baseload energy source necessary to achieve a reliable, secure, and diversified electric grid. The Commission hosted its first Nuclear Summit examining developments around the deployment of new reactors.

Legislation: H.B. 863

Enacted June 2020

Exempts nuclear generating facilities from county, municipal, and district ad valorem taxes, instead requiring the utility pay the state Department of Revenue a sum based on the assessed value of such nuclear generating plant.

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Legislation: S.B. 2928
Enacted April 2019

Authorizes the Board of Trustees of the Vicksburg Warren School District and the Claiborne County Board of Education to establish a partnership with the Entergy Grand Gulf Nuclear Station, Warren County, and the Mississippi Development Authority for a Nuclear Energy High School Academy.

Legislation: S.B. 2793
Enacted May 2008

Authorizes the Public Service Commission to include in an electric utility's rates certain pre-construction, construction work in progress, operating and other costs incurred in connection with certain new baseload generating facilities, including nuclear.

MISSOURI

Legislation: S.B. 1388
Enacted July 2024

Authorizes a state and local sales tax exemption for all sales and purchases of tangible personal property, building materials, equipment, fixtures, manufactured goods, machinery, and parts for the purposes of constructing all or any portion of a nuclear security enterprise, as such term is defined in the act, located in Kansas City.

MONTANA

Legislation: H.B. 273
Enacted May 2021

Removes a provision in the Montana Major Facility Siting Act which required the public to approve any proposed nuclear energy facilities through a statewide election.

Resolution: Senate Joint Resolution 3
Adopted May 2021

Requires a study of the feasibility of advanced nuclear generation, including an evaluation of the economic feasibility of replacing closing coal facilities with advanced nuclear reactors. Link to study.

NEBRASKA

Feasibility Study
Released August 2024

In 2022, the legislature gave $1 million to the Nebraska Department of Economic Development to fund a feasibility study. Phase 1 of the study considered areas across the entire state, including current generation sites. Sixteen sites have been identified to proceed to the second phase of the feasibility study. Link to Phase 1 SMR Siting Technical Screening Study.

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Legislation: L.B. 568
Enacted May 2023 (portions amended into LB565 in June 2023)

Establishes a 12-member working group appointed by the Governor to study and determine the workforce training needs of the nuclear and hydrogen industries.

Legislation: L.B. 1014
Enacted April 2022

Appropriates $1 million to the state Department of Economic Development for use by a political subdivision that owns or operates a nuclear plant in the state to conduct an advanced reactor feasibility study.

Legislation: L.B. 84
Enacted May 2021

Adds nuclear energy to the qualifying renewable energy sources eligible for a business tax incentive.

NEW HAMPSHIRE

Legislation: H.B. 1465
Enacted August 2024

Requires the Department of Energy to coordinate the continuing studies of state agencies on the uses and development of nuclear energy, including advanced nuclear reactors.

Legislation: H.B. 543
Enacted June 2022

Establishes a Commission to study nuclear power and nuclear reactor technology in New Hampshire. Link to Final Report.

NEW JERSEY

Regulation: Docket No. ER20080557-9 New Jersey Board of Public Utilities
Ordered April 2021

Renews the zero-emission credit program for Hope Creek and Salem nuclear power plants for an additional three years.

Regulation: Docket No. EO18080899, EO18121337-9 New Jersey Board of Public Utilities
Ordered April 2019

The Board of Public Utilities approves a zero-emissions credit program for Hope Creek and Salem nuclear power plants.

Legislation: S.B. 2313
Enacted May 2018

Requires the New Jersey Board of Public Utilities to create a zero-emission certificate program that would provide up to $300 million annually to support qualifying low carbon electricity sources, such as nuclear power.

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NEW MEXICO

Resolution: House Memorial 57
Adopted February 2014

Requests a study to determine the feasibility, societal benefits, and required regulatory changes associated with the deployment of small modular reactors.

NEW YORK

Draft Blueprint: Consideration for Advanced Nuclear Technologies
Released September 2024

The New York State Energy Research and Development Authority (NYSERDA) released its draft blueprint for consideration of advanced nuclear technologies.

Regulation: Cases 15-E-0302 and 16-E-0270 New York Public Service Commission
Ordered August 2016

Establishes a clean energy program and allows for the creation of a zero-emission credit program to preserve certain existing zero-emission nuclear generation in the state.

NORTH CAROLINA

Regulation: Docket No. E-100 Sub 179 North Carolina Utilities Commission
Ordered November 2024

The North Carolina Utilities Commission issued an order accepting the Consolidated Carbon Plan and Integrated Resource Plan (CPIRP) establishing a least-cost path forward for Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC. The plan includes the approval of $440 million for continued development work and early site permits for two SMRs, totaling 600 MW of new nuclear capacity online by 2035. The order also requires Duke to submit a report by March 2025 detailing Duke's infrastructure that could support new large light water reactors and encourages the company to pursue subsequent license renewals for its existing nuclear fleet.

Legislation: S.B. 678
Enacted October 2023

Replaces statutory definition of renewable energy with clean energy. Includes nuclear and fusion in definition of clean energy.

Regulation: Docket No. E-100 Sub 179 North Carolina Utilities Commission
Ordered December 2022

Requires Duke Energy Carolinas to pursue license extensions for its existing nuclear fleet and authorizes the utility to incur project development costs associated with new nuclear generation. The Commission requires the utility to report on the status of license extensions for the existing nuclear fleet, as well as activities and costs incurred in support of new nuclear generation as part of the utility’s combined carbon plan and integrated resource plan due to the Commission on Sept. 1, 2023.

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Legislation: H.B. 951
Enacted October 2021

Establishes utility carbon reduction goals of 70% of 2005 levels by 2030 and 95% by 2050 and requires utilities to submit a carbon reduction plan to the NC Utilities Commission by December 31, 2022.

Regulation: Docket No. E-7 Sub 819 North Carolina Utilities Commission
Ordered June 2008

Allows Duke Energy to recover certain development costs associated with construction of the Lee Nuclear Generating Station.

Legislation: S.B. 3
Enacted August 2007

Allows public utilities to apply for advance determination of prudence for construction of "resource additions" such as renewable energy facilities, transmission facilities, demand response, and energy conversion facilities.

NORTH DAKOTA

Resolution: House Concurrent Resolution 3034
Adopted April 2023

Recommends the state study sustainable energy policies to maximize the economic viability of existing energy sources, assess future demands on electricity in the state, and determine the feasibility of advanced nuclear energy development and transmission in the state.

Resolution: House Concurrent Resolution 3015
Adopted March 2023

Urges the federal government to recognize natural gas and nuclear energy as environmentally sustainable economic activities.

Legislation: H.B. 1221
Enacted April 2011

Allows public utilities to apply for advance determination of prudence for construction of "resource additions" such as renewable energy facilities, transmission facilities, demand response, and energy conversion facilities.

OHIO

Legislation: H.B 308
Enacted December 2024

Defines energy generated by nuclear reaction as green energy.

Legislation: H.B. 33
Enacted July 2023

Establishes the Ohio Nuclear Development Authority within the Ohio Department of Development and included $750,000 to establish an Ohio State Nuclear Technology Research Program that will develop and study advanced nuclear research reactors.

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Legislature Launches a Nuclear Energy Caucus
2019 Legislative Session

Resolution: House Resolution 518
Adopted 2017

Petitions the U.S. Department of Energy to establish rules and programs that would allow states, in collaboration with the federal government, to develop new nuclear technologies and laboratories and to construct facilities to conduct nuclear-related testing.

Regulation: Case No. 08-888-EL-ORD Ohio Public Service Commission
Ordered April 2009

Authorizes the development of an alternative energy standard requiring 25% of total energy be met by alternative sources, including nuclear.

Legislation: S.B. 221
Enacted May 2008

Establishes the state's alternative energy resource standard and includes nuclear in its definition of an advanced energy resource.

OKLAHOMA

Legislation: S.B. 1535
Enacted April 2024

Establishes a Low Carbon Initiative that includes nuclear.

Resolution: Senate Resolution 30
Adopted March 2024

Urges the federal government to implement permitting reform. (including nuclear)

PENNSYLVANIA

Resolution: House Resolution 238
Adopted November 2022

Directs the Joint State Government Commission to conduct a holistic study on the benefits of nuclear energy and small modular reactors. Link to study.

Legislators Launch a Bicameral, Bipartisan Nuclear Energy Caucus and Release the "Bicameral Nuclear Energy Caucus Report."
2017-2018 Legislative Session

Legislation: S.B. 227/H.B. 576
Enacted October 2017

Urges the Federal Energy Regulatory Commission (FERC) to implement policies to ensure fuel secure generation resources like nuclear energy receive proper compensation for the positive attributes they provide the nation's electric system.

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Legislation: H.B 750
Enacted June 2012

Memorializes the President and the U.S. Congress to provide for the storage of used nuclear fuel.

SOUTH CAROLINA

Legislation: S. 1031
Enacted July 2024

Adds requirement of Nuclear Advisory Council to engage stakeholders and develop a strategic plan to advance the development of advanced reactors.

Legislation: H. 5100
Enacted March 2024

Appropriates $10 million to the Department of Commerce for SC Nexus.

Legislation: H. 4300
Enacted July 2023

Includes $40,000,000 in the budget for the Battelle Alliance at Savannah River National Lab of which twenty percent shall be allocated to South Carolina State University, forty percent to the University of South Carolina, and forty percent to Clemson University.

Resolution: S. 822
Adopted June 2023

Congratulates Duke Energy's Oconee Nuclear Station upon the occasion of its fiftieth anniversary and commends the station for its many years of dedicated service to Oconee County and the people and the state of South Carolina.

Legislation: H. 4940
Enacted September 2020

Establishes the Electricity Market Reform Measures Study Committee to consider whether the Legislature should adopt electricity market reform measures and recognizes the carbon-free and economic benefits of nuclear power.

Legislation: S. 232
Enacted May 2009

Requires that strategies of the state energy office promoting carbon-free clean energy must include nuclear energy, renewable energy sources, and conservation and efficiency measures.

Regulation: Docket No. 2007-440-E South Carolina Public Service Commission
Ordered June 2008

Approves Duke Energy's decision to incur pre-construction project development costs for the proposed Lee Nuclear Station.

Legislation: S. 431
Enacted May 2007

Allows the Public Service Commission to grant a project development order for nuclear projects and a base load review order for any base load facility, including nuclear projects.

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SOUTH DAKOTA

Legislation: H.B. 1071
Enacted March 2024

Revises a provision providing authority to the Governor to enter into agreements with the Nuclear Regulatory Commission. Language changes included a focus on NRC rather than generic federal government label.

Resolution: Senate Concurrent Resolution 601
Adopted February 2023

Encourages the legislature to consider establishing an interim legislative committee to examine the potential use of nuclear power in South Dakota, to include a nuclear power plant, for the establishment of a safe, clean, and reliable source of energy for South Dakota.

Regulation: Docket No. EL23-002 South Dakota Public Utilities Commission
Ordered February 28, 2023

The Commission approved Northwestern Energy's request to allow for deferred accounting treatment beginning March 1, 2023 for costs to study new nuclear.

TENNESSEE

Final Report
Released November 2024

Tennessee Nuclear Energy Advisory Council delivered its final report. The council's report includes 19 recommendations in five key areas that reinforce Tennessee's leading position in the nuclear industry and will enable deployment of critical baseload energy and support for a vibrant nuclear ecosystem that is key to the state's overall economy. Link to report.

Legislation: H.B. 2118
Enacted May 2024

Increases the number of council members from 15 to 22. Includes two representatives from Oak Ridge (one non-voting member appointed by Governor and one voting member appointed by Speaker of the Senate); one representative with expertise in radiological control or nuclear criticality safety or nuclear wastes; one representative of the nuclear manufacturing industry; and one representative who is involved in innovative energy production.

Legislation: H.B. 0946/ S.B. 1389
Enacted July 2023

Establishes that nuclear power is a permissible source of clean energy used by a public utility. The legislation also established that nuclear power is a permissible source of renewable energy used by a public utility.

Executive Order: Executive Order 101
Enacted May 2023

Creates the Tennessee Nuclear Energy Advisory Council, which seeks to build upon the state's legacy in nuclear innovation and drive continued investment to create a nuclear energy ecosystem for the future of Tennessee. Link to order.

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State Budget: 2024
Enacted May 2023

$50 million to the Tennessee Department of Economic and Community Development to develop nuclear supply chain companies.

Resolution: House Joint Resolution 507
Adopted March 2016

Supports the research and development of liquid core molten salt reactors and small modular reactors technologies as a long-term solution to the state's energy needs.

Resolution: Senate Joint Resolution 92
Adopted April 2015

Encourages the Nuclear Regulatory Commission to support the license application of the Tennessee Valley Authority related to the safe operation of Watts Bar Nuclear Plant Unit 2.

TEXAS

Final Report
Released November 2024

Governor Greg Abbott and the Public Utility Commission of Texas (PUCT) released the Texas Advanced Nuclear Reactor Working Group's final report which includes seven key recommendations to the state legislature. Link to report.

Executive Action: Governor's Instruction
August 2023

The Governor instructed the Public Utility Commission of Texas (PUCT) to establish a working group to study and plan for the use of advanced reactors in Texas. The working group will submit a plan and recommendations to the Governor by December 1, 2024. Link to instruction.

Legislature Launches Bipartisan Nuclear Energy Caucus
2023 Legislative Session

Legislation: H.B. 1
Enacted June 2023

Provides $18.5 million over two years to support University of Texas at Austin's Digital Molten Salt Reactor Initiative.

Resolution: House Concurrent Resolution 81
Adopted April 2013

Commemorates the 50th anniversary of the agreement between the state of Texas and the Nuclear Regulatory Commission regarding radioactive materials.

Legislation: H.B. 1386
Enacted May 2007

Gives the Public Service Commission authority to regulate decommissioning trust funds for up to six new nuclear power plants under construction before 2015.

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Legislation: H.B. 2994
Enacted May 2007

Expands existing legislation that enables local taxing authorities to grant property tax abatements adding new nuclear plants and integrated gasification combined cycle facilities as eligible projects.

UTAH

Legislation: H.B. 48
Enacted March 2024

Instructs state agencies to participate in federal rulemaking process leading to reform of regulations and permitting; fund development of detailed forecasts of the state's long-term energy supply demand. Expands upon the strategic energy plan which includes the use and development of nuclear power.

Legislation: H.B. 124
Enacted March 2024

Modifies definitions and qualifications applicable to the high-cost infrastructure development tax credit. "Energy delivery project" includes nuclear power generation systems.

Legislation: H.B. 241
Enacted March 2024

Amends the state's energy provisions relating to clean energy by changing the term "renewable" to "clean" where appropriate in the statute.

Legislation: H.B. 426
Enacted July 2023

Requires the Office of Energy Development to prepare a strategic energy plan that includes nuclear energy.

Resolution: Senate Concurrent Resolution 6
Adopted March 2019

Supports the development and integration of advanced nuclear reactor technology as a way of supporting the state's continued economic growth while addressing the health of the environment and of state residents.

Legislation: S.B. 24
Enacted March 2019

Amends the state energy policy to promote nuclear generation technologies including molten salt reactors for producing medical isotopes.

Legislation: H.B. 169
Enacted March 2018

Reduces the annual fee paid by an owner or operator of a commercial radioactive waste treatment or disposal facility that receives radioactive waste.

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Legislation: S.B. 65
Enacted March 2012

Provides tax incentives for alternative energy development and manufacturing and includes nuclear energy in the definition.

Legislation: H.B. 430
Enacted March 2009

Provides incentives to develop renewable energy projects, including nuclear energy generation facilities, in order to spur economic development.

Resolution: Senate Joint Resolution 16
Adopted March 2009

Encourages new nuclear plant development in Utah for its beneficial impacts on the economy, fuel diversification, and the environment.

VIRGINIA

Legislation: S.B. 454
Enacted April 2024

Allows Dominion Energy to petition the State Corporation Commission at any time for the approval of a rate adjustment clause for the recovery of small modular reactor project development costs for up to one small modular reactor facility, as well as for project development cost recovery along separate development phases.

Legislation: H.B. 1491
Enacted April 2024

Allows American Electric Power, prior to the filing of an application for a certificate to construct a small modular nuclear facility, to request the State Corporation Commission to review such utility's decision to incur project development costs and seek cost recovery.

Legislation: H.B. 2386/ S.B. 1464
Enacted March 2023

Establishes the Virginia Power Innovation Fund; the Virigina Power Innovation Program; and the Virigina Nuclear Innovation Hub.

Legislation: H.B. 1779
Enacted March 2023

Establishes the Nuclear Education Grant Fund and Program, for the purpose of awarding grants on a competitive basis to any public or private higher education institution that seeks to establish or expand a nuclear education program.

Legislation: H.B. 894
Enacted July 2022

Directs the Virginia Department of Energy, in cooperation with the Virginia Nuclear Energy Consortium Authority, to convene a stakeholder working group to identify strategies and any needed public policies, including statutory or regulatory changes, for promoting the development of advanced small modular reactors in the Commonwealth.

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Resolution: Senate Joint Resolution 60
Adopted April 2020

Encourages the advancement of nuclear energy research and the exploration of economic development opportunities related to nuclear energy.

Legislation: H.B. 981
Enacted April 2020

Mandates that the state joins the Regional Greenhouse Gas Initiative.

Legislation: S.B. 828
Enacted April 2020

Amends the definition of carbon-free energy or clean energy to include electric energy generated from a source that does not emit carbon dioxide during generation, including nuclear energy.

Legislation: S.B. 817
Enacted April 2020

Broadens statute definition of clean energy to include nuclear generation.

Legislation: H.B. 1303/S.B. 549
Enacted April 2020

Directs several state agencies to work in coordination with the Nuclear Energy Consortium Authority to develop a strategic plan for the role of nuclear energy in the state's overall strategy for moving toward renewable and carbon-free energy.

Legislation: H.B. 2008/S.B. 1348
Enacted March 2019

Directs the state Department of Education to work in consultation with pertinent industries, such as nuclear energy, to establish the energy career cluster.

Legislation: H.B. 2291
Enacted March 2017

Authorizes an investor-owned utility to petition the State Corporation Commission for certain cost recovery for the license renewal and nuclear plant upgrades necessary for operating in the license renewal period, including second license renewal.

Legislation: S.B. 459*
Enacted April 2014
***Struck April 2020**

Establishes that planning and development for new nuclear generation facilities are in the public interest and allows nuclear development costs to be included in base rates.

Legislation: S.B. 1138/H.B. 1790
Enacted March 2013

Establishes the Virginia Nuclear Energy Consortium Authority to make Virginia a national and global leader in nuclear energy, and to serve as an interdisciplinary study, research, and information resource on nuclear energy issues.

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Legislation: H.B. 3068/S.B. 1416
Enacted April 2007

Amends the ratemaking procedure of the State Corporation Commission and requires that the determined rate of return on common equity shall not be lower than the average rate of return of other investor-owned electric utilities in the southeastern U.S.

WASHINGTON

Legislation: S.B. 5949
Enacted May 2024

Provides $25,000,000 solely as nonfederal support for Energy Northwest's participation in the United States department of energy's loan programs office part 2 application, including due diligence review and environmental impact review.

Legislature Launches Nuclear Energy Caucus
2023 Legislative Session

Governor's Proclamation
Signed 2016-2022

In recognition of nuclear science and technology for National Nuclear Science Week.

Legislation: S.B. 5116
Enacted May 2019

Enacts a clean electricity standard, eliminating coal generation by 2025 and mandating 100% clean energy by 2045.

Legislation: S.B. 6002
Enacted 2014

Creates a joint select task force on nuclear energy to study the potential of nuclear power in the region.

WEST VIRGINIA

Resolution: Senate Concurrent Resolution 11
Adopted January 2024

Urges Congress to enact much-needed reforms to federal permitting policies to accelerate energy infrastructure (including nuclear).

Legislation: H.B. 2814
Enacted May 2023

Creates a hydrogen power task force to study clean hydrogen, including hydrogen produced by nuclear.

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Resolution: House Concurrent Resolution 11
Adopted February 2023

Urges the state's institutions of higher education to establish an education consortium to assist the state government with the development of policies and programs necessary to facilitate nuclear energy developments in West Virginia.

Legislation: S.B. 4/H.B. 2882
Enacted April 2022

Repeals the moratorium on the construction of new nuclear facilities within the state.

WISCONSIN

Legislation: Act 344
Enacted April 2016

Repeals the moratorium on the construction of new nuclear facilities within the state.

Legislation: Act 7
Enacted May 2005

Allows the PSC to issue an order specifying in advance the rate-making principles that will apply to a new electric generating facility (built or purchased) before construction commences or the purchase contract is closed.

WYOMING

Funding: Energy Matching Funds
Announced June 2024

Wyoming Energy Authority awards Phase Two of the $20 million cost share program to assess the viability of deploying small-scale nuclear reactors in the state as a source of resilient and reliable energy to augment existing power generation resources.

Funding: Energy Matching Funds
Announced December 2023

Wyoming Energy Authority provides $10 million to assess microreactor deployment in Wyoming.

Legislation: H.B. 131
Enacted March 2022

Reduces barriers to the deployment of advanced reactor technologies and removes, under certain circumstances, a tax on nuclear electricity generation.

Legislation: H.B. 74
Enacted March 2020

Authorizes permits for small modular reactors (SMRs) to replace coal- or natural gas-generating units so long as the SMR's rated capacity is not greater than 300 megawatts (MW).

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Legislation: S.F. 23
Enacted March 2016

Enters applicable state agencies into NRC agreement authorization to regulate certain nuclear adjacent commodities.

Legislation: H.B. 27
Enacted March 2015

Enters applicable state agencies into NRC agreement authorization to regulate certain nuclear adjacent commodities.

Legislation: S.F. 14
Enacted March 2012

Directs the Wyoming Business Council to partner with the Department of Energy to study the feasibility of locating advanced nuclear facilities within the state.

Legislation: S.F. 12
Enacted March 2012

Directs the Taskforce on Nuclear Energy Production to study a variety of nuclear energy issues with the primary goal of incentivizing the development of new facilities within the state.

Legislation: H.B. 129
Enacted March 2011

Creates a task force on nuclear energy production to study ways to encourage nuclear power in Wyoming including tax incentives, water rights, public-private partnerships, state laws, storage and reprocessing technologies, and higher education.

ADDITIONAL RESOURCES

National Association of Regulatory Utility Commissioners:

- Nuclear Generation in Long-Term Utility Resource Planning
- Nuclear Energy as a Keystone Clean Energy Resource

National Conference of State Legislatures:

- What Role Will Nuclear Energy Play in the Clean Energy Transition?
- State Options to Keep Nuclear in the Energy Mix
- State Renewable Portfolio Standards and Goals
- State Restrictions on New Nuclear Power Facility Construction

National Governors Association:

- State Policy Support for Nuclear Generation

Nuclear Energy Institute:

- State Policy Options to Support New Nuclear Energy
- State Fact Sheets
- Oxford Report on Economic Contribution of Nuclear Energy in the United States

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Exhibit L-C1-SEC-030, Attachment 23

North American Utilities Regulatory Jurisdictions Update:
Connecticut And Mississippi Assessments Revised,
Other Notable Developments

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 24

S&P Global Ratings
Ameren Corp.

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 25

S&P Global Ratings
American Electric Power Co. Inc.

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 26

S&P Global Ratings
Dominion Energy Inc.'s Announcement To Explore SMR Nuclear Advancement Has No Immediate Credit Implications

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 27

S&P Global Ratings
Dominion Energy Inc.

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 28

S&P Global Ratings
Duke Energy Corp. And Subsidiaries Ratings
Affirmed Following Atlantic Coast Pipeline Exit;
Outlook Stable

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 29

S&P Global Ratings
Duke Energy Corp. Can Maintain Credit Quality Amid
Extensive Storm Restoration Costs

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 30

S&P Global Ratings
Entergy Corp.

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 31

S&P Global Ratings
Evergy Inc.

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 32

S&P Global Ratings
Pinnacle West Capital Corp.

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 33

S&P Global Ratings
Southern Co.

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 34

S&P Global Ratings
Southern Co. Upgraded To 'A-' On Commercial Operations
Of Nuclear Power Plant; Various Actions Taken On Subsidiaries

This Attachment was filed as confidential information in its entirety.

Exhibit L-C1-SEC-030, Attachment 35

S&P Global Ratings
Xcel Energy Inc.

This Attachment was filed as confidential information in its entirety.

SEC Interrogatory #031

Interrogatory

Reference:
C1-1-1, Attachment 1

Question(s):

With respect to the Concentric Energy Advisors ("Concentric"), *Common Equity Ratio Study,* please explain how, if all, Concentric considered each of the following in its assessment of OPG business risks:

a) The impact of Darlington NGS and Pickering NGS post-refurbishment on unplanned outages and other risks.

b) OPG's view that the Darlington Refurbishment Program ("DRP") came in on-time and on-budget.

c) Government of Ontario's willingness to treat DNNP separately through O.Reg 53/05.

d) Government of Ontario's support for nuclear generation.

e) Rate framework sought by OPG in this application.

f) Proposed new DVA accounts sought by OPG in this application.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) The replacement of life-limited components as part of the Darlington and Pickering refurbishments reduces failure risk, and the modernization of systems reduces the risk of degradation-driven outages. At the same time, the initial period of operations post-major equipment replacement and refurbishment pose risks related to design modifications. For example, Southern California Edison permanently shut down its San Onofre Nuclear Generating Station in 2012 after tube leaks were discovered in its recently replaced steam generators. While that is not a specific risk identified for OPG, it is an example of an industry challenge that can occur post-refurbishment that inform investors' views of nuclear-related risks.

b) As discussed in Concentric's report (Ex. C1-1-1 Attachment 1, p. 11), "OPG has successfully managed the Darlington Refurbishment Project ("DRP"), a $12.8 billion mega project that is nearing completion. As such, OPG has demonstrated corporate competency in large nuclear refurbishments and will be able to apply lessons learned from the DRP to the PRP. The PRP, however, is anticipated to cost more than double the cost of the DRP and involves a more aged plant, which leads to increased scope and increases risks related to the discovery of additional scope and challenges during the refurbishment process."

c) Concentric's analysis specifically excludes consideration of the Darlington New Nuclear Program.

d) Concentric's consideration in its report regarding support from the Ontario Government is focused on the provisions of O.Reg. 53/05 that provide for certain cost recovery mechanisms that support OPG's nuclear plans. See, for instance, Section 5 of Concentric's report titled Market/Industry Assessment: Industry Pathways to Supporting Increasing Electricity Demand, Energy Security, and the Energy Transition.

e) As noted in Concentric's report (Ex. C1-1-1 Attachment 1, p. 5) OPG's base rates for its prescribed hydroelectric facilities were last set in EB-2016-0152 using a price-cap index Custom IR framework prior to being set legislatively at the 2021 rate for the 2022-2026 period. Under the price-cap framework, the rates are set based on a cost of service approach for a test year, which is then escalated in subsequent years of the rate term by an inflation and productivity factor. Concentric understands that in this application, OPG is proposing to continue to set regulated hydroelectric rates using a price-cap index Custom IR framework but with the addition of a custom capital factor designed to ensure adequate funding for capital projects required over the forecast period, as well as a factor to remove the application of escalation of its gross revenue charge costs.

   OPG's prescribed nuclear rates have generally been set using a Custom IR framework that includes specific revenue requirements for each of the five years, with incremental stretch reductions designed to create an incentive for continuous improvement. Concentric understands that OPG is proposing to continue setting nuclear rates using this previously approved form of Custom IR in this application.

f) See Concentric's response to Ex. L-C1-CCC-025.

SEC Interrogatory #032

Interrogatory

Reference:
C1-1-1, Attachment 1, p. 68-69, 77

Preamble:
With respect to the Concentric Energy Advisors ("Concentric"), *Common Equity Ratio Study*, Concentric discusses the unique nature of OPG as a "pure-play generator" and the only one included in the peer groups.

Question(s):

a) In light of the unique nature of OPG as a "pure-play generator", please explain why Concentric did not include companies in its analysis that are primarily power generation, even if it is not rate regulated (i.e. independent power producers with significant contracted assets such as Boralex Inc., Northland Power Inc. Brookfield Renewable Partners L.P, and TransAlta).

b) Please undertake an analysis similar to the other peer groups in the Report for IPP companies referenced in part a. and provide a comparison of equity thickness.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Concentric did not include non-regulated (also known as "merchant") generators, or independent power producers ("IPPs") in its analysis because they are not risk-comparable for purposes of setting a regulated return. IPPs have a different revenue model than OPG's regulated businesses in that their revenues are set in the market, not through cost-based ratemaking, and IPPs do not have access to deferral and variance accounts and other regulatory cost recovery mechanisms that are available to regulated utilities. As such, these companies present a different risk profile for investors than does OPG as a rate-regulated entity. In addition, whereas Brookfield Renewable Partners L.P. ("BEP") and Northland Power Inc. ("Northland") have investment grade credit ratings from S&P (BBB+ and BBB, respectively), TransAlta Corporation ("TransAlta") is rated below investment grade by S&P (BB+) and Boralex Inc. does not have a credit rating. Further, these IPPs use primarily non-recourse debt to finance their power projects, with investors in that debt having no claim on the assets of the parent company. As such, the equity ratios of these companies at the corporate level range from approximately 22%

(i.e., TransAlta, which is sub-investment grade rated) to approximately 86% (i.e., Northland) and averaged approximately 62% in 2025. Capitalization at the corporate level excluding non-recourse debt is the appropriate measure of financial risk for these companies, as project lenders of non-recourse debt do not have a claim on the assets of the parent company. To that point, in its ratings report on BEP, S&P states, "[w]e evaluate the company's credit metrics on a deconsolidated basis by considering only holding company recourse debt and not project-level nonrecourse debt in our analysis." Similarly, in its report on Northland, S&P states "We consider only corporate-level (recourse) debt."

b) In terms of the proxy group screening analysis that Concentric performed, the IPP companies fail every screening criterion except for the credit rating screen, which two of the companies (i.e., BEP and Northland) meet. As noted in the response to part a), TransAlta is rated BB+ and Boralex is unrated.

Concentric's analysis in its report included an evaluation of the proxy group companies' regulatory adjustment mechanisms, operating profiles (i.e., breakdown of generation, transmission and distribution operations) and generation mix.

In terms of regulatory adjustment mechanisms, the IPP companies do not have key regulatory items such as adjustment clauses and cost recovery mechanisms that allow utilities to recover prudently incurred costs in a timely manner and reduce regulatory risk to investors, and no IPP company is included in S&P's Adjustment Mechanisms report.

In terms of operating profiles, each of the IPPs operates primarily in the generation segment. Of those assets, the table below provides a breakdown by generation type. As shown in the table, none of the companies have nuclear generation facilities, and Northland also has no hydroelectric facilities. In addition, whereas OPG operates primarily baseload generation assets, the IPPs have significant amount of intermittent wind and solar generation in their mixes.

Company	Hydro-electric (%)	Wind (%)	Solar (%)	Distributed Energy and Storage (%)	Other (%)	Total (%)
BEP	19%	37%	31%	12%	0%	100%
Northland	0%	72%	0%	7%	21%	100%
TransAlta	10%	29%	0%	0%	61%	100%
Boralex	5%	78%	7%	10%	0%	100%

Regarding equity thickness, none of the IPPs have authorized equity ratios, so it is not possible to provide that portion of Concentric's proxy group analysis. The tables below provides the actual equity ratios over the period 2021-2025 at the corporate level for each of the IPPs requested in the interrogatory.

2025					
Company	**Debt (Corporate)**	**Equity**	**Debt (%)**	**Equity (%)**	**Source**
BEP	3,686	8,876	29%	71%	Brookfield Renewable Partners L.P. 2025 Annual Report, at 6 and 29.
Northland	720,881	4,424,542	14%	86%	Northland Power 2025 Annual Report, at 45 and 49.
TransAlta	1,900	523	78%	22%	TransAlta 2025 Annual Report, at F11 and F68.
Boralex	646	1,542	30%	70%	Boralex 2025 Annual Report, at 47.
		Average (%)	**38%**	**62%**	

1

2024					
Company	**Debt (Corporate)**	**Equity**	**Debt (%)**	**Equity (%)**	**Source**
BEP	3,802	8,380	31%	69%	Brookfield Renewable Partners L.P. 2024 Annual Report, at 6 and 27.
Northland	664,895	4,556,413	13%	87%	Northland Power 2024 Annual Report, at 41 and 45.
TransAlta	1,981	901	69%	31%	TransAlta 2024 Annual Report, at M48, M51, and F76.
Boralex	424	1,601	21%	79%	Boralex 2024 Annual Report, at 43 and 110.
		Average (%)	**33%**	**67%**	

2

2023					
Company	**Debt (Corporate)**	**Equity**	**Debt (%)**	**Equity (%)**	**Source**
BEP	2,833	9,181	24%	76%	Brookfield Renewable Partners L.P. 2023 Annual Report, at 6 and 26
Northland	644,996	4,482,724	13%	87%	Northland Power 2023 Annual Report, at 38 and 42.
TransAlta	1,776	722	71%	29%	TransAlta 2023 Annual Report, at M36, M38, and F72.

2023					
Company	**Debt (Corporate)**	**Equity**	**Debt (%)**	**Equity (%)**	**Source**
Boralex	483	1,629	23%	77%	Boralex 2023 Annual Report, at 59 and 125.
		Average (%)	**33%**	**67%**	

1

2022					
Company	**Debt (Corporate)**	**Equity**	**Debt (%)**	**Equity (%)**	**Source**
BEP	2,548	9,608	21%	79%	Brookfield Renewable Partners L.P. 2022 Annual Report at 7 and 29
Northland	(2,817)	4,724,273	0%	100%	Northland Power 2022 Annual Report, at 36 and 40.
TransAlta	1,613	1,047	61%	39%	TransAlta 2022 Annual Report, at M28, M31, and F72.
Boralex	339	1,681	17%	83%	Boralex 2022 Annual Report at 93 and 118.
		Average (%)	**25%**	**75%**	

2

2021					
Company	**Debt (Corporate)**	**Equity**	**Debt (%)**	**Equity (%)**	**Source**
BEP	2,149	9,607	18%	82%	Brookfield Renewable Partners L.P. 2021 Annual Report at 8 and 30
Northland	41,816	2,965,711	1%	99%	Northland Power 2021 Annual Report, at 34 and 38.
TransAlta	1,139	1651	41%	59%	TransAlta 2021 Annual Report at M32, M35, and F67.
Boralex	541	1,001	35%	65%	Boralex 2021 Annual Report at 96 and 121.
		Average (%)	**24%**	**76%**	

3

SEC Interrogatory #033

Interrogatory

Reference:
C1-1-1

Question(s):

Please provide a table showing for each year between 2008 and 2026, the approved ROE included in base rates and the actual ROE (and forecast ROE for 2026) for each of, a) combined OPG, b) hydroelectric business, and c) nuclear business. Please provide full calculations for all actual ROE.

Response

a) to c)
Chart 1 below provides, for OPG's prescribed facilities, the OEB-approved ROE for 2008-2026, actual ROE for 2008-2024, preliminary actual ROE for 2025 and the forecast ROE for 2026. Refer to Attachment 1 (Confidential) for the calculations of the actual ROE for 2008-2024. For the calculations of the 2025 preliminary actual ROE, refer to Ex. L-I1-Staff-266. For the calculations of the 2026 forecast ROE, refer to Ex. I1-1-1, Table 5.

As stated in EB-2020-0290, Ex. L-A1-03-Staff-008, OPG operates as a single company, with a single management structure, a single corporate cost structure, and a single OEB-authorized cost of capital that covers both the hydroelectric and nuclear generating facilities, and obtains corporate financing as a single company. Accordingly, OPG does not have a technology specific OEB-approved or actual ROE.

Chart 1: Summary of OPG's OEB-Approved and Actual ROE

Year	OEB Approved ROE (%)	Actual ROE (%)	Attachment Page
2008	8.65%	(3.11)%	1
2009	8.65%	1.10%	2
2010	N/A	4.71%	5
2011	9.43%	4.80%	8
2012	9.55%	4.73%	11
2013	N/A	0.46%	14
2014	9.36%	6.31%	17
2015	9.30%	3.63%	20
2016	N/A	3.80%	23
2017	9.23%	6.02%	26
2018	9.16%	10.72%	29
2019	9.16%	15.72%	32
2020[1]	9.06%	17.44%	35
2021	9.05%	10.79%	38
2022	8.97%	12.41%	41
2023	8.97%	13.71%	44
2024	8.93%	5.86%	47
2025 (Preliminary)	8.92%	13.02%	Ex. L-I1-Staff-266 Att. 1
2026 (Forecast)	8.91%	5.63%	Ex. I1-1-1, Table 5

[1] Refer to Ex. C1-1-1, Table 12, line 5, col. (c).

Numbers may not add due to rounding.

Table 5
Capitalization and Cost of Capital
Summary of Capitalization and Actual Cost of Capital ($M)
Calendar Year Ending Dec. 31, 2008

Line No.	Capitalization	Note	Principal ($M) Q1 (45% Equity)	Q2-Q4 (47% Equity)	((a) x .25 + (b) x .75) Annualized	Component (%)	Actual Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Achieved Capitalization and Return on Capital:							
1	**Short-term Debt**	1	169.6	169.6	169.6	2.7%	4.10%	7.7
2	**Existing Long-Term Debt**	2	2,052.5	2,052.5	2,052.5	32.2%	5.78%	118.7
3	**Other Long-Term Debt Provision**	3	1,812.6	985.5	1,192.2	18.7%	5.66%	67.5
4	**Total Debt**	4	4,034.6	3,207.5	3,414.3	53.6%	5.68%	193.9
5	**Common Equity**	4, 5	3,301.1	2,844.4	2,958.6	46.4%	-3.11%	(92.0)
6	**Rate Base Financed by Capital Structure**	6	7,335.7	6,052.0	6,372.9	86.9%	1.60%	102.0
7	**Adjustment for Lesser of UNL or ARC**	6, 7		1,283.7	962.8	13.1%	5.60%	53.9
8	**Rate Base**	8	7,335.7	7,335.7	7,335.7	100%	2.13%	155.9

Notes:

1 Short Term Financing allocated at: 56.3%
Short-term Debt Cost includes interest at the cost rate shown plus an allocation of the credit facility cost shown at Ex. C1-T1-S3 Table 2, line 10.
2 Q1 and Q2-Q4 from Ex. C1-T1-S2 Table 3 (line 28).
3 Debt req'd to balance capital structure with proposed rate base. See Ex . C1-T1-S2 Table 3a Note 10 for interest rate calculation.
4 Q2-Q4 Capital Structure approved by the OEB in EB-2007-0905 as discussed in Ex. C1-T1-S1.
5 Col. (f) from Ex. C1-T1-S1 Table 7 line 14 for 2008.
6 The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.
7 Col. (b) from C2-T1-S2 Table 1, line 29.
8 Ex. B1-T1-S1 Table 1 (Regulated Hydroelectric) and Ex. B1-T1-S1 Table 2 (Nuclear).

Numbers may not add due to rounding.

Table 4
Capitalization and Cost of Capital
Summary of Capitalization and Actual Cost of Capital ($M)
Calendar Year Ending Dec. 31, 2009

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Actual Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Achieved Capitalization and Return on Capital:					
1	**Short-term Debt**	1	186.2	3.1%	1.58%	6.6
2	**Existing Long-Term Debt**	2	2,019.8	33.1%	5.82%	117.5
3	**Other Long-Term Debt Provision**	3	1,024.6	16.8%	6.76%	69.3
4	**Total Debt**	4	3,230.6	53.0%	5.99%	193.4
5	**Common Equity**	4, 5	2,864.9	47.0%	1.10%	31.6
6	**Rate Base Financed by Capital Structure**	6	6,095.5	84.0%	3.69%	225.0
7	**Adjustment for Lesser of UNL or ARC**	6, 7	1,159.8	16.0%	5.60%	65.0
8	**Rate Base**	8	7,255.4	100%	4.00%	290.0

Notes:

1 Short Term Financing allocated at: 64.7%
Short-term Debt Cost includes interest at the cost rate shown plus an allocation of the credit facility cost shown at Ex. C1-T1-S3 Table 2, line 10.

2 Ex. C1-T1-S2 Table 4 (line 31).

3 Debt req'd to balance capital structure with proposed rate base. See Ex . C1-T1-S2 Table 4a Note 11 for interest rate calculation.

4 Capital Structure approved by the OEB in EB-2007-0905 as discussed in Ex. C1-T1-S1.

5 For actual Return on Equity achieved for 2009 see Ex. C1-T1-S1 Table 7.

6 The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

7 From C2-T1-S2 Table 1, line 29.

8 Ex. B1-T1-S1 Table 1 (Regulated Hydroelectric) and Ex. B1-T1-S1 Table 2 (Nuclear).

Numbers may not add due to rounding.

Table 7
Capitalization and Cost of Capital
Actual Return on Equity - Reconciliation to Audited Financial Statements for Prescribed Facilities ($M)
Calendar Years Ending December 31, 2008 and December 31, 2009

Line No.	Description	Note	Regulated Hydroelectric 2008	Nuclear 2008	Total 2008	Regulated Hydroelectric 2009	Nuclear 2009	Total 2009
			(a)	(b)	(c)	(d)	(e)	(f)
1	**Accounting EBIT (includes rounding)**	1	309.9	(538.4)	(228.5)	326.5	279.6	606.1
Accounting Expenses/Revenues not Included in Regulatory EBIT								
2	**Add: Accretion on Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities**	2	0.0	325.9	325.9	0.0	344.8	344.8
3	**Deduct: Earnings/(Losses) on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds**	2	0.0	(242.1)	(242.1)	0.0	415.5	415.5
Differences Between Accounting and Regulatory Treatment								
	(1) HYDROELECTRIC PRODUCTION ABOVE 1900 MW/Hr:							
4	**Deduct: Revenue at Market Price Included in Accounting EBIT**	3	189.0	0.0	189.0	0.0	0.0	0.0
5	**Add: Revenue at Regulated Hydroelectric Payment Amounts**	4	125.4	0.0	125.4	0.0	0.0	0.0
	(2) HYDROELECTRIC INCENTIVE MECHANISM:							
6	**Deduct: Hydroelectric Incentive Revenue**	5	3.0	0.0	3.0	21.0	0.0	21.0
	(3) CAPITAL TAXES:							
7	**Add: Accounting Capital Tax on Regulated Assets**	6	11.7	8.5	20.2	10.5	7.3	17.8
8	**Deduct: Regulatory Capital Tax on Regulated Assets**	7	8.7	7.8	16.5	8.6	7.7	16.3
	(4) UNREALIZED EXCHANGE RATE ADJUSTMENTS:							
9	**Add: (Gains)/Losses Included in Accounting EBIT**	8	0.0	(7.9)	(7.9)	0.0	0.0	0.0
10	**Regulatory EBIT** (line 1+2-3-4+5-6+7-8+9)		246.3	22.4	268.7	307.4	208.5	515.8
Cost Related to Deemed Debt and UNL/ARC Adjustment								
11	**Deduct: Cost of Deemed Debt for Regulated Assets**	9	117.7	76.3	193.9	121.7	71.8	193.5
12	**Deduct: Cost Related to UNL/ARC Adjustment**	9	N/A	53.9	53.9	N/A	65.0	65.0
13	**Regulatory EBT** (line 10 - line 11 - line 12)	10	128.7	(107.8)	20.8	185.7	71.7	257.3
Determination of Return on Equity								
14	**Deduct: Income Taxes on Regulated Assets**	11	0.0	0.0	0.0	23.0	45.0	68.0
Systematic Adjustments								
15	**Deduct: Transactions in Income and Other Taxes Variance**	12	(0.2)	(11.7)	(11.9)	(0.1)	(8.4)	(8.5)
16	**Deduct: Transactions in Tax Loss Variance Account**	12	20.0	104.7	124.7	26.6	139.6	166.2
17	**Total Systematic Adjustments**		19.8	93.0	112.8	26.5	131.2	157.7
18	**Return on Equity** (line 13 - line 14 - line 17)		108.9	(200.8)	(92.0)	136.2	(104.6)	31.6

See Ex. C1-T1-S1 Table 7a for notes

Numbers may not add due to rounding.

Table 7a
Capitalization and Actual Cost of Capital
Actual Return on Equity - Reconciliation to Audited Financial Statements for Prescribed Facilities($M)
Notes to Ex. C1, Tab 1, Sch. 1, Table 7

Notes:

1 Accounting EBIT for 2008 and 2009 as reflected in the audited financial statements for prescribed facilities in Ex. A2-T1-S1 Attachment 3.
Nuclear EBIT consists of EBIT of the Nuclear Generation and Nuclear Waste Management segments in the audited financial statements for prescribed facilities.

2 Accretion on Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities and Earnings/Losses on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds for 2008 and 2009 as reflected in the Nuclear Waste Management segment in the audited financial statements for prescribed facilities in Ex. A2-T1-S1 Attachment 3. Accretion for 2009 and Fund Earnings/(Losses) for 2008 and 2009 are also presented in Ex. C2-T1-S2 Table 1. Accretion for 2008 presented in Ex. C2-T1-S2 Table 1 differs from the amount per the audited financial statements for prescribed facilities as the amount in the financial statements reflects a reduction for amounts deferred in the Nuclear Liability Deferral Account, Transition during Q1 2008.

3 Revenue at Market Price for 2008 as reflected on page 29 in Management's Discussion and Analysis accompanying OPG's 2009 audited consolidated financial statements in Ex. A2-T1-S1 Attachment 2 .
Regulated Hydroelectric production above 1900 MWh/Hr does not receive market prices effective December 1, 2008, as discussed in Ex. E1-T1-S1.

4 Revenue at Regulated Hydroelectric Payment Amounts for 2008 is computed as total hourly production over 1900 MWh x $33.00/MWh for Q1 2008 and $36.66/MWh for April 1 to November 30, 2008.

5 Hydroelectric Incentive Revenue for 2008 and 2009 is earned pursuant to the revised hydroelectric incentive mechanism approved by the OEB in EB-2007-0905 effective December 1, 2008, and is reflected on page 29 in Management's Discussion and Analysis accompanying OPG's 2009 audited consolidated financial statements in Ex. A2-T1-S1 Attachment 2. The hydroelectric incentive mechanism is discussed in Ex. E1-T1-S1.

6 Capital Tax included in Accounting EBIT is based on an allocation of accounting capital taxes to prescribed assets determined on a corporate basis.

7 Capital Tax for regulatory purposes for OPG's prescribed assets is determined in Ex. F4-T2-S1 Tables 2 and 4.

8 OPG recognizes certain unrealized exchange rate gains/losses in Accounting EBIT for derivatives related to some of its future purchase obligations. For regulatory purposes, any such gains/losses are reflected in the cost of actual purchases as they are received.

9 Interest cost of deemed debt allocated to Regulated Hydroelectric and Nuclear based on rate base as follows:

Table to Note 9 - Interest Expense Calculation ($M)		Regulated Hydroelectric			Nuclear		
Line		2008			2008		
No.	Item	Q1	Q2 - Q4	2009	Q1	Q2 - Q4	2009
		(a)	(b)	(c)	(d)	(e)	(f)
1	Interest Rate (from Ex. C1-1-1 Tables 4, 5)	5.68%	5.68%	5.99%	5.68%	5.68%	5.99%
2	Rate Base (from B1-1-1 Tables 1 and 2)	3,871.5	3,871.5	3,834.0	3,464.2	3,464.2	3,421.4
3	ARC / UNL Adjustment (Ex. C2-1-2 Table 1)	N/A	N/A	N/A	0.0	1,283.7	1,159.8
4	Rate base financed by capital structure	3,871.5	3,871.5	3,834.0	3,464.2	2,180.5	2,261.5
	(line 2 - line 3)						
5	Debt Ratio	55%	53%	53%	55%	53%	53%
6	Deemed Debt (line 4 x line 5)	2,129.3	2,051.9	2,032.0	1,905.3	1,155.7	1,198.6
7	Proportion of year	25%	75%	100%	25%	75%	100%
8	Cost of Deemed Debt for Regulated Assets	30.2	87.4	121.7	27.1	49.2	71.8
	(line 1 x line 6 x line 7)						
9		2008 Total >	117.7		2008 Total >	76.3	
10	Cost Related to UNL/ARC Adjustment	N/A	N/A	N/A	0.0	53.9	65.0
	(5.60% line 3 x line 7)						

10 Regulatory EBT for 2008 and 2009 is used to determine regulatory income taxes in Ex. F4-T2-S1 Table 6.

11 Regulatory income taxes for 2008 and 2009 as reflected in Ex. F4-T2-S1 Tables 1 and 3.

12 Ex. H1-T1-S1 Tables 1b and 1c.

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Ontario Power Generation Inc.
EB-2010-0008 Reporting and Record Keeping Requirements

Table 1
Summary of Capitalization and Cost of Capital
Year Ended December 31, 2010

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
1	**Short-term Debt**	1	195.1	3.2%	1.37%	5.0
2	**Existing Long-term Debt**	1	2,128.4	34.5%	5.54%	117.8
3	**Other Long-term Debt Provision**	1, 3	949.6	15.4%	4.68%	44.5
4	**Total Debt**	4	3,273.1	53.0%	5.11%	167.3
5	**Common Equity**	4, 5	2,902.6	47.0%	4.71%	136.7
6	**Rate Base Financed by Capital Structure**	4	6,175.6	80.3%	4.92%	304.0
7	**Adjustment for Lesser of UNL or ARC**	1	1,517.6	19.7%	5.58%	84.7
8	**Rate Base**	1	7,693.3	100.0%	5.05%	388.6

Notes:

1 Actual amounts in cols. (a) and (d) and cost rate in col. (c) for 2010 determined using the same methodologies applied in EB-2007-0905 / EB-2010-0008.

2 The cost of short-term debt includes interest at the cost rate shown plus an allocation of the actual credit facility cost for 2010.

3 Debt required to balance capital structure with actual rate base for 2010.

4 Capital structure as approved by the OEB in EB-2007-0905 / EB-2010-0008.

5 Actual regulatory return on equity for 2010 in col. (d) as per Table 2, line 12, col (c).

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Ontario Power Generation Inc.
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Table 2
Calculation of Regulatory Return on Equity ($M)
Year Ended December 31, 2010

Line No.	Description	Note	Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
1	**Accounting EBIT (includes rounding)**	1	316.4	154.5	470.9
Accounting Expenses/Revenues not Included in Regulatory EBIT					
2	**Add: Accretion on Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities**	1	0.0	[redacted]	[redacted]
3	**Deduct: Earnings/(Losses) on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds**	1	0.0	[redacted]	[redacted]
Differences Between Accounting and Regulatory Treatment					
4	**Deduct: Hydroelectric Incentive Revenue**	2	[redacted]	0.0	[redacted]
5	**Add: Accounting Capital Tax on Regulated Assets**	1	10.0	[redacted]	[redacted]
6	**Deduct: Regulatory Capital Tax on Regulated Assets**	3	7.4	9.3	16.8
7	**Regulatory EBIT** (line 1+2-3-4+5-6)		304.7	116.9	421.6
Cost Related to Deemed Debt and UNL/ARC Adjustment					
8	**Deduct: Cost of Deemed Debt for Regulated Assets**	4	102.9	64.4	167.3
9	**Deduct: Cost Related to UNL/ARC Adjustment**	4	N/A	84.7	84.7
10	**Regulatory EBT** (line 7 - line 8 - line 9)		201.8	(32.2)	169.6
Determination of Regulatory Return on Equity					
11	**Deduct: Income Taxes on Regulated Assets**	5	30.1	2.8	32.9
12	**Regulatory Return on Equity** (line 10 - line 11)		171.7	(35.0)	136.7

See Table 2a for notes

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Ontario Power Generation Inc.
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Table 2a
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2010
Notes to Table 2

Notes:

1 Amounts at lines 1, 2, 3 and 5 for 2010 are determined in accordance with Canadian Generally Accepted Accounting Principles as defined in Part V of the Canadian Institute of Chartered Accountants Handbook – Accounting and are as reflected in the 2010 audited financial statements for the prescribed facilities filed in EB-2012-0002. Nuclear accounting EBIT at line 1 consists of Nuclear Generation and Nuclear Waste Management segments in the audited financial statements for the prescribed facilities.

2 Hydroelectric Incentive Revenue for 2010 is earned pursuant to the hydroelectric incentive mechanism approved by the OEB in EB-2007-0905. [redacted].

3 Capital Tax for regulatory purposes for OPG's prescribed facilities is determined based on actual rate base at line 8, col. (a) of Table 1 using the same methodology applied in EB-2007-0905 / EB-2010-0008, as adjusted for 2010 variance and deferral account additions related to capital tax variances.

4 Cost related to deemed debt and UNL/ARC adjustment for 2010 is allocated to Regulated Hydroelectric and Nuclear based on actual rate base, using the same methodology applied in EB-2007-0905 / EB-2010-0008, as follows:

Table to Note 4 ($M)

Line No.	Item	Regulated Hydroelectric	Nuclear
		(a)	(b)
1a	Interest Rate (Table 1, line 4, col. (c))	5.11%	5.11%
2a	Actual Rate Base (Table 1, line 8, col. (a))	3,798.0	3,895.3
3a	ARC / UNL Adjustment (Table 1, line 7, col. (a))	N/A	1,517.6
4a	Rate Base Financed by Capital Structure	3,797.9	2,377.7
	(line 2a - line 3a)		
5a	Debt Ratio (Table 1, line 4, col. (b))	53%	53%
6a	Deemed Debt (line 4a x line 5a)	2,012.9	1,260.2
7a	Cost of Deemed Debt for Regulated Assets	102.9	64.4
	(line 1a x line 6a)		
8a	Cost Related to UNL/ARC Adjustment	N/A	84.7
	(Table 1, line 7, col. (c) x line 3a)		

5 Regulatory income taxes are determined based on Regulatory EBT at line 10, using the methodology for the calculation of regulatory income taxes in the EB-2010-0008 Payment Amounts Order, as adjusted for 2010 variance and deferral account additions impacting regulatory income taxes. The calculation of 2010 regulatory income taxes reflects information as per OPG's 2010 income tax return filed with the Ontario Ministry of Finance.

Numbers may not add due to rounding.

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Ontario Power Generation Inc.
EB-2010-0008 Reporting and Record Keeping Requirements

Table 1
Summary of Actual Capitalization and Cost of Capital
Year Ended December 31, 2011

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
1	**Short-term Debt**	1	194.2	3.2%	1.78%	6.5
2	**Existing Long-term Debt**	1	2,300.0	37.5%	5.23%	120.2
3	**Other Long-term Debt Provision**	1, 3	760.3	12.4%	5.23%	39.7
4	**Total Debt**	4	3,254.4	53.0%	5.12%	166.5
5	**Common Equity**	4, 5	2,886.0	47.0%	4.80%	138.4
6	**Rate Base Financed by Capital Structure**	4	6,140.4	80.5%	4.97%	304.9
7	**Adjustment for Lesser of UNL or ARC**	1	1,490.0	19.5%	5.58%	83.1
8	**Rate Base**	1	7,630.4	100.0%	5.09%	388.0

Notes:

1 Actual amounts in cols. (a) and (d) and cost rate in col. (c) for 2011 determined using the same methodologies applied in EB-2010-0008.

2 The cost of short-term debt includes interest at the cost rate shown plus an allocation of the actual credit facility cost for 2011.

3 Debt required to balance capital structure with actual rate base for 2011.

4 Capital structure as approved by the OEB in EB-2010-0008.

5 Actual regulatory return on equity for 2011 in col. (d) as per Table 2, line 13, col (c).

Numbers may not add due to rounding.

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Ontario Power Generation Inc.
EB-2010-0008 Reporting and Record Keeping Requirements

Table 2
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2011

Line No.	Description	Note	Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
1	**Accounting EBIT (includes rounding)**	1	342.6	(9.8)	332.8
Accounting Expenses/Revenues not Included in Regulatory EBIT:					
2	**Add: Accretion on Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities**	1	0.0	[redacted]	[redacted]
3	**Deduct: Earnings/(Losses) on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds**	1	0.0	[redacted]	[redacted]
Differences Between Accounting and Regulatory Treatment:					
4	**Deduct: Shareholder Portion of Hydroelectric Incentive Mechanism Revenue**	2	[redacted]	0.0	[redacted]
5	**Deduct: Shareholder Portion of Heavy Water Sales Net of Costs**	3	0.0	[redacted]	[redacted]
6	**Add: Accounting Capital Tax on Regulated Assets**	1	[redacted]	[redacted]	[redacted])
7	**Deduct: Regulatory Capital Tax on Regulated Assets**	4	1.6	1.2	2.8
8	**Regulatory EBIT** (lines 1+2-3-4-5+6)		331.3	123.5	454.8
Cost Related to Deemed Debt and UNL/ARC Adjustment:					
9	**Deduct: Cost of Deemed Debt for Regulated Assets**	5	102.3	64.2	166.5
10	**Deduct: Cost Related to UNL/ARC Adjustment**	5	N/A	83.1	83.1
11	**Regulatory EBT** (line 8 - line 9 - line 10)		229.0	(23.9)	205.2
Determination of Regulatory Return on Equity:					
12	**Deduct: Regulatory Income Taxes on Regulated Assets**	6	34.4	32.4	66.8
13	**Regulatory Return on Equity** (line 11 - line 12)		194.7	(56.3)	138.4

See Table 2a for notes

Numbers may not add due to rounding.

Revised: July 7, 2014

Ontario Power Generation Inc.
EB-2010-0008 Reporting and Record Keeping Requirements

Table 2a
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2011
Notes to Table 2

Notes:

1 Amounts at lines 1, 2, 3 and 6 for 2011 are determined in accordance with Canadian Generally Accepted Accounting Principles as defined in Part V of the Canadian Institute of Chartered Accountants Handbook - Accounting and are as reflected in the 2011 audited financial statements for the prescribed facilities filed in EB-2012-0002. Nuclear accounting EBIT at line 1 consists of Nuclear Generation and Nuclear Waste Management segments in the audited financial statements for the prescribed facilities.

2 Hydroelectric Incentive Mechanism ("HIM") revenue for 2011 is earned pursuant to the hydroelectric incentive mechanism approved by the OEB in EB-2010-0008.
The shareholder portion of HIM revenue is comprised of 100% of actual revenue for January and February 2011 and 50% of actual revenue for the remainder of 2011 pursuant to the sharing mechanism established in EB-2010-0008. [redacted]

3 In EB-2010-0008, the OEB determined that the approved revenue requirement should reflect a reduction equal to 50% of the forecast heavy water sales net of costs. The shareholder portion of heavy water sales net of costs represents the difference between the actual sales net of costs for the ten-month period ended December 31, 2011 and the portion for the same period of the full-year revenue requirement reduction for 2011 as per the EB-2010-0008 Payment Amounts Order.

4 As capital tax was eliminated effective July 1, 2010, the full amount of capital tax for regulatory purposes represents the 2011 variance and deferral account additions related to capital tax variances.

5 Cost related to deemed debt and UNL/ARC adjustment for 2011 is allocated to Regulated Hydroelectric and Nuclear based on actual rate base, using the same methodology applied in EB-2010-0008, as follows:

Table to Note 5 ($M)

Line No.	Item	Regulated Hydroelectric	Nuclear
		(a)	(b)
1a	Interest Rate (Table 1, line 4, col. (c))	5.12%	5.12%
2a	Actual Rate Base (Table 1, line 8, col. (a))	3,771.8	3,858.6
3a	ARC / UNL Adjustment (Table 1, line 7, col. (a))	N/A	1,490.0
4a	Rate Base Financed by Capital Structure	3,771.8	2,368.6
	(line 2a - line 3a)		
5a	Debt Ratio (Table 1, line 4, col. (b))	53%	53%
6a	Deemed Debt (line 4a x line 5a)	1,999.1	1,255.4
7a	Cost of Deemed Debt for Regulated Assets	102.3	64.2
	(line 1a x line 6a)		
8a	Cost Related to UNL/ARC Adjustment	N/A	83.1
	(Table 1, line 7, col. (c) x line 3a)		

6 The amount of regulatory income taxes is determined based on Regulatory EBT at line 11, using the methodology for the calculation of regulatory income taxes in the EB-2010-0008 Payment Amounts Order, as adjusted for 2011 variance and deferral account additions impacting regulatory income taxes. The calculation of 2011 regulatory income taxes reflects information as per OPG's 2011 income tax return filed with the Ontario Ministry of Finance.

Numbers may not add due to rounding.

Revised: July 7, 2014

Ontario Power Generation Inc.
EB-2010-0008 Reporting and Record Keeping Requirements

Table 1
Summary of Actual Capitalization and Cost of Capital
Year Ended December 31, 2012

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
1	**Short-term Debt**	1	7.2	0.1%	1.79%	3.4
2	**Existing Long-term Debt**	1	2,287.6	38.0%	5.13%	117.3
3	**Other Long-term Debt Provision**	1, 3	898.9	14.9%	5.13%	46.1
4	**Total Debt**	4	3,193.7	53.0%	5.23%	166.9
5	**Common Equity**	4, 5	2,832.2	47.0%	4.73%	133.9
6	**Rate Base Financed by Capital Structure**	4	6,025.9	76.5%	4.99%	300.8
7	**Adjustment for Lesser of UNL or ARC**	1, 6	1,851.1	23.5%	5.43%	100.5
8	**Rate Base**	1	7,876.9	100.0%	5.09%	401.3

Notes:

1 Actual amounts in cols. (a) and (d) and the cost rate in col (c) for 2012 are determined using the same methodologies applied in EB-2010-0008.
2 The cost of short-term debt includes interest at the cost rate shown plus an allocation of the actual credit facility cost for 2012.
3 Debt required to balance capital structure with actual rate base for 2012.
4 Capital structure as approved by the OEB in EB-2010-0008.
5 Actual regulatory return on equity for 2012 in col. (d) as per Table 2, line 13, col (c).
6 Cost rate from EB-2012-0002, Ex L-1-7, SEC 11, Chart 2.

Numbers may not add due to rounding.

Revised: July 7, 2014

Ontario Power Generation Inc.
EB-2010-0008 Reporting and Record Keeping Requirements

Table 2
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2012

Line No.	Description	Note	Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
1	**Accounting EBIT (includes rounding)**	1	324.3	115.8	440.1
Accounting Expenses/Revenues not Included in Regulatory EBIT:					
2	**Add: Accretion on Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities**	1, 7	0.0	[redacted]	[redacted]
3	**Deduct: Earnings/(Losses) on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds**	1, 8	0.0	[redacted]	[redacted]
Differences Between Accounting and Regulatory Treatment:					
4	**Deduct: Shareholder Portion of Hydroelectric Incentive Mechanism Revenue**	2	[redacted]	0.0	[redacted]
5	**Deduct: Shareholder Portion of Heavy Water Sales Net of Costs**	3	0.0	[redacted]	[redacted]
6	**Add: Accounting Capital Tax on Regulated Assets**	1	[redacted]	[redacted]	[redacted]
7	**Deduct: Regulatory Capital Tax on Regulated Assets**	4	N/A	N/A	N/A
8	**Regulatory EBIT** (lines 1+2-3-4-5+6)		315.5	147.1	462.6
Cost Related to Deemed Debt and UNL/ARC Adjustment:					
9	**Deduct: Cost of Deemed Debt for Regulated Assets**	5	103.7	63.2	166.9
10	**Deduct: Cost Related to UNL/ARC Adjustment**	5	N/A	100.5	100.5
11	**Regulatory EBT** (line 8 - line 9 - line 10)		211.8	(16.6)	195.2
Determination of Regulatory Return on Equity:					
12	**Deduct: Regulatory Income Taxes on Regulated Assets**	6	33.5	27.8	61.3
13	**Regulatory Return on Equity** (line 11 - line 12)		178.3	(44.4)	133.9

See Table 2a for notes

Numbers may not add due to rounding.

Revised: July 7, 2014

Ontario Power Generation Inc.
EB-2010-0008 Reporting and Record Keeping Requirements

Table 2a
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2012
Notes to Table 2

Notes:

1 Actual amounts on lines 1, 2, 3 and 6 are determined in accordance with United States Generally Accepted Accounting Principles ("USGAAP"), as approved in EB-2012-0002 for use by OPG for regulatory accounting, reporting and rate-making purposes effective January 1, 2012. The amounts are as reflected in the 2012 audited financial statements for the prescribed facilities filed in EB-2013-0321. Nuclear accounting EBIT at line 1 consists of Nuclear Generation and Nuclear Waste Management segments in the audited financial statements for the prescribed facilities.

2 Hydroelectric Incentive Mechanism ("HIM") revenue for 2012 is earned pursuant to the hydroelectric incentive mechanism approved by the OEB in EB-2010-0008. The shareholder portion of HIM revenue is comprised of 50% of actual revenue for 2012 pursuant to the sharing mechanism established in EB-2010-0008. [redacted]

3 In EB-2010-0008, the OEB determined that the approved revenue requirement should reflect a reduction equal to 50% of the forecast heavy water sales net of costs. The shareholder portion of heavy water sales net of costs represents the difference between the actual sales net of costs for the year ended December 31, 2012 and the revenue requirement reduction for 2012 as per the EB-2010-0008 Payment Amounts Order.

4 There is no capital tax for regulatory purposes for OPG's prescribed facilities for 2012, as capital tax was eliminated effective July 1, 2010 and there are no additions in 2012 to deferral and variance accounts related to capital tax variances.

5 Cost related to deemed debt and UNL/ARC adjustment for 2012 is allocated to Regulated Hydroelectric and Nuclear based on actual rate base, using the same methodology applied in EB-2010-0008, as follows:

Table to Note 5 ($M)

Line No.	Item	Regulated Hydroelectric	Nuclear
		(a)	(b)
1a	Interest Rate (Table 1, line 4, col. (c))	5.23%	5.23%
2a	Actual Rate Base (Table 1, line 8, col. (a))	3,744.0	4,132.9
3a	ARC / UNL Adjustment (Table 1, line 7, col. (a))	N/A	1,851.1
4a	Rate Base Financed by Capital Structure	3,744.0	2,281.9
	(line 2a - line 3a)		
5a	Debt Ratio (Table 1, line 4, col. (b))	53%	53%
6a	Deemed Debt (line 4a x line 5a)	1,984.3	1,209.4
7a	Cost of Deemed Debt for Regulated Assets	103.7	63.2
	(line 1a x line 6a)		
8a	Cost Related to UNL/ARC Adjustment	N/A	100.5
	(Table 1, line 7, col. (c) x line 3a)		

6 The amount of regulatory income taxes is determined based on Regulatory EBT at line 11, using the methodology for the calculation of regulatory income taxes in the EB-2010-0008 Payment Amounts Order, as adjusted to reflect the inclusion of income tax amounts in certain deferral and variance accounts and inclusion of 2012 SR&ED ITCs in income tax expense as required by USGAAP as explained in EB-2012-0002 Ex. A3-1-2 section 4.2.1. The calculation of 2012 regulatory income taxes reflects information as per OPG's 2012 income tax return filed with the Ontario Ministry of Finance.

7 The amount is presented on the same basis as reported in OPG's 2012 audited consolidated financial statements and the 2012 audited financial statements for the prescribed facilities filed in EB-2013-0321. This represents the following: the accretion expense on the nuclear decommissioning waste management removal and nuclear waste management liabilities of $432.6M (found at EB-2012-0002 Ex. H1-1-2 Table 18, line 6), plus other related costs of $0.3M, less $21.8M for the return on rate base component of 2012 additions to the Nuclear Liability Deferral Account (found at EB-2012-0002 Ex. H1-1-1 Table 9, line 4).

8 Found at EB-2012-0002 Ex. H1-1-2 Table 18, col (c), line 15.

Numbers may not calculate due to rounding.

Submitted: July 7, 2014

Ontario Power Generation Inc.
EB-2010-0008 Reporting and Record Keeping Requirements

Table 1
Summary of Actual Capitalization and Cost of Capital[1]
Year Ended December 31, 2013

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
1	**Short-term Debt**	2,3,4	10.7	0.1%	1.17%	2.2
2	**Existing Long-term Debt**	2, 4	2,514.2	35.2%	5.09%	128.0
3	**Other Long-term Debt Provision**	2,4,5	1,258.3	17.6%	5.09%	64.0
4	**Total Debt**	6, 7	3,783.2	53.0%	5.13%	194.2
5	**Common Equity**	6,7,8	3,354.9	47.0%	0.46%	15.3
6	**Rate Base Financed by Capital Structure**	6	7,138.2	82.9%	2.93%	209.5
7	**Adjustment for Lesser of UNL or ARC**	2,7,9	1,470.2	17.1%	5.37%	78.9
8	**Rate Base**	2, 7	8,608.3	100.0%	3.35%	288.4

Notes:

1 Newly regulated hydroelectric facilities are not included as they are not prescribed until July 1, 2014.
2 Amounts in cols. (a) and (d) and the cost rate in col. (c) for 2013 are determined using the same methodologies applied in EB-2010-0008.
3 The cost of short-term debt includes interest at the cost rate shown plus an allocation of the actual credit facility cost for 2013.
4 Amount in col. (a) differs from EB-2013-0321, L-1.0-1 Staff-002, Att. 1, Table 5, col. (a) because amounts in that table did not reflect the updated 2013 debt allocation ratio for the regulated operations which was developed subsequent to the filing of the EB-2013-0321 interrogatory responses (as noted in Note 1 to that table).
5 Debt required to balance capital structure with actual rate base for 2013.
6 Capital structure as approved by the OEB in EB-2010-0008.
7 Amount in col. (a) as shown in EB-2013-0321, L-1.0-1, Staff-002, Att. 1, Table 5, col. (a).
8 Actual regulatory return on equity for 2013 in col. (d) as per Table 2, line 15, co.l (c).
9 Cost rate as discussed in EB-2013-0321, Ex. L-9.1-17 SEC-129.

Numbers may not calculate due to rounding.

Submitted: July 7, 2014

Ontario Power Generation Inc.
EB-2010-0008 Reporting and Record Keeping Requirements

Table 2
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2013

Line No.	Description	Note	Previously Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
1	**Accounting EBIT (includes rounding)**	1	338.4	(312.5)	25.9
Accounting Expenses/Revenues not Included in Regulatory EBIT:					
2	**Add: Accretion on Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities**	1, 8	0.0	[redacted]	[redacted]
3	**Deduct: Earnings/(Losses) on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds**	1, 9	0.0	[redacted]	[redacted]
Differences Between Accounting and Regulatory Treatment:					
4	**Deduct: Shareholder Portion of Hydroelectric Incentive Mechanism Revenue**	2	[redacted]	0.0	[redacted]
5	**Deduct: Shareholder Portion of Heavy Water Sales Net of Costs**	3	0.0	[redacted]	[redacted]
6	**Add: Accounting Capital Tax on Regulated Assets**	1	[redacted]	[redacted]	[redacted]
7	**Deduct: Regulatory Capital Tax on Regulated Assets**	4	N/A	N/A	N/A
8	**Add: Pickering Life Extension Depreciation Variance Account Impact on EBT**	5	0.0	21.1	21.1
9	**Regulatory EBIT** (lines 1+2-3-4-5+6+7+8)		329.4	(196.8)	132.6
Deemed Cost of Capital:					
10	**Deduct: Cost of Deemed Debt for Regulated Assets**	6	131.3	62.8	194.2
11	**Deduct: Cost Related to UNL/ARC Adjustment**	6	N/A	78.9	78.9
12	**Add: Cost of Capital Variance Account Additions**	10	79.4	4.5	83.8
13	**Regulatory EBT** (line 9 - line 10 - line 11 + line 12)		277.4	(334.1)	(56.7)
Determination of Regulatory Return on Equity:					
14	**Deduct: Regulatory Income Taxes on Regulated Assets**	7	0.2	(72.2)	(72.0)
15	**Regulatory Return on Equity** (line 13 - line 14)		277.2	(261.9)	15.3

See Table 2a for notes

Numbers may not calculate due to rounding.

Submitted: July 7, 2014

Ontario Power Generation Inc.
EB-2010-0008 Reporting and Record Keeping Requirements

Table 2a
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2013
Notes to Table 2

Notes:

1 Actual amounts on lines 1, 2, 3 and 6 are determined in accordance with United States Generally Accepted Accounting Principles ("USGAAP"), as approved in EB-2012-0002 for use by OPG for regulatory accounting, reporting and rate-making purposes effective January 1, 2012. These amounts are determined using the same methodology reflected in the 2012 audited financial statements for the prescribed facilities filed in EB-2013-0321 .

2 Hydroelectric Incentive Mechanism ("HIM") revenue for 2013 is earned pursuant to the hydroelectric incentive mechanism approved by the OEB in EB-2010-0008. The shareholder portion of HIM revenue is comprised of 50% of actual revenue for 2013 pursuant to the sharing mechanism established in EB-2010-0008. [redacted]

3 In EB-2010-0008, the OEB determined that the approved revenue requirement should reflect a reduction equal to 50% of the forecast heavy water sales net of costs. The shareholder portion of heavy water sales net of costs represents the difference between the actual sales net of costs for the year ended December 31, 2013 and the average revenue requirement reduction for 2011 and 2012 as per the EB-2010-0008 Payment Amounts Order.

4 There is no capital tax for regulatory purposes for OPG's prescribed facilities for 2013, as capital tax was eliminated effective July 1, 2010 and there are no additions in 2013 to deferral and variance accounts related to capital tax variances.

5 The Pickering Life Extension Depreciation Variance Account Impact on EBT represents the regulatory EBT impact of the 2013 depreciation addition to, and amortization of, the Pickering Life Extension Depreciation Variance Account. In accordance with USGAAP, these impacts were not recognized in OPG's 2013 audited consolidated financial statements and therefore are not reflected in Accounting EBIT at line 1. The amount of the adjustment is computed as the amortization credit of $56.3M per EB-2012-0002 Payment Amounts Order, App. B, Table B-1 less the $35.2M depreciation expense credit (per EB-2012-0002 Ex. M1-1-1, Att. 3, Table 1, line 5) recorded in the variance account. This adjustment was not reflected in the initial calculation of the Regulatory EBT and Regulatory ROE shown at EB-2013-0321 Ex. L-1.0-1, Staff-002, Att. 1, Table 29, line 1 and Table 5, col. (d), line 5, respectively.

6 Cost related to deemed debt and UNL/ARC adjustment for 2013 is allocated to Previously Regulated Hydroelectric and Nuclear based on actual rate base, using the same methodology applied in EB-2010-0008, as follows:

Table to Note 5 ($M)

Line No.	Item	Previously Regulated Hydroelectric	Nuclear
		(a)	(b)
1a	Interest Rate (Table 1, line 4, col. (c))	5.13%	5.13%
2a	Actual Rate Base (Table 1, line 8, col. (a))	4,828.5	3,779.8
3a	ARC / UNL Adjustment (Table 1, line 7, col. (a))	N/A	1,470.2
4a	Rate Base Financed by Capital Structure	4,828.5	2,309.7
	(line 2a - line 3a)		
5a	Debt Ratio (Table 1, line 4, col. (b))	53%	53%
6a	Deemed Debt (line 4a x line 5a)	2,559.1	1,224.1
7a	Cost of Deemed Debt for Regulated Assets	131.3	62.8
	(line 1a x line 6a)		
8a	Cost Related to UNL/ARC Adjustment	N/A	78.9
	(Table 1, line 7, col. (c) x line 3a)		

7 The amount of regulatory income taxes is determined based on Regulatory EBT at line 13, using the methodology for the calculation of regulatory income taxes in the EB-2010-0008 Payment Amounts Order, as adjusted to reflect the inclusion of income tax amounts in certain deferral and variance accounts and inclusion of 2013 SR&ED ITCs in income tax expense as required by USGAAP as explained in EB-2012-0002 Ex. A3-1-2, section 4.2.1 and EB-2013-0321 Ex. A2-1-1, section 4.0. The calculation of 2013 regulatory income taxes reflects information as per OPG's 2013 income tax returns filed with the Ontario Ministry of Finance at the end of June 2014.

8 The amount is presented on the same basis as reported in OPG's 2013 audited consolidated financial statements and the 2012 audited financial statements for the prescribed facilities filed in EB-2013-0321. This represents the following: the accretion expense on the nuclear decommissioning waste management removal and nuclear waste management liabilities of $442.7M (found at EB-2013-0321 Ex. L1.0-1 Staff-002, Att. 1, Table 7, col. (a), line 6), plus other related costs of $0.3M, less $2.1M for the return on rate base component of 2013 additions to the Nuclear Liability Deferral Account (found at EB-2013-0321 Ex. L9.1-17 SEC-132, Att. 1, Table 10, line 4).

9 Found at EB-2013-0321 Ex. L1.0-1 Staff-002, Att. 1, Table 7, col. (a), line 15.

10 The amount represents the cost of capital additions to the Nuclear and Previously Regulated Hydroelectric capital portions of the Capacity Refurbishment Variance Account. For Previously Regulated Hydroelectric, this represents $83.1M for the Niagara Tunnel Project shown at Ex. L-9.1-17 SEC-132, Att. 1, Table 7, col. (c), line 5 less a credit of $3.8M for the three Sir Adam Beck 1 facility projects reflected at Ex. L-9.1-17 SEC-132, Att. 1, Table 7, lines 13-15. For Nuclear, this represents the amount for the Darlington Refurbishment Project as shown at Ex. L-9.1-17 SEC-132, Att. 1, Table 12a, col. (c), line 3.

Numbers may not calculate due to rounding.

Submitted: July 7, 2015

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 1
Summary of Actual Capitalization and Cost of Capital[1]
Year Ended December 31, 2014

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
1	**Short-term Debt**	2,3	72.7	0.7%	1.20%	4.3
2	**Existing Long-term Debt**	2	3,181.7	32.2%	5.01%	159.5
3	**Other Long-term Debt Provision**	2,4	2,007.6	20.3%	5.01%	100.6
4	**Total Debt**	5	5,262.0	53.3%	5.03%	264.5
5	**Common Equity**	5,6	4,610.4	46.7%	6.31%	290.9
6	**Rate Base Financed by Capital Structure**	5	9,872.4	87.7%	5.63%	555.4
7	**Adjustment for Lesser of UNL or ARC**	2	1,389.4	12.3%	5.37%	74.6
8	**Rate Base**	2	11,261.8	100.0%	5.59%	630.0

Notes:

1 Newly regulated hydroelectric facilities are included for the full year beginning on January 1, 2014, as presented in the EB-2013-0321 Payment Amounts Order. For the period January 1, 2014 to October 31, 2014, revenues for newly regulated hydroelectric production are based on electricity market prices, which these facilities received prior to the implementation of the EB-2013-0321 payment amounts effective November 1, 2014.

2 Amounts in cols. (a) and (d) and the cost rates in col. (c) are determined using the same methodologies as applied in EB-2010-0008 and EB-2013-0321.

3 The cost of short-term debt includes interest at the cost rate shown in col. (c) plus an allocation of the actual credit facility cost.

4 Debt required to balance capital structure with actual rate base.

5 For January to October 2014, the capital structure reflects 53% debt and 47% equity approved in EB-2010-0008. Effective November 1, 2014, the capital structure reflects 55% debt and 45% equity approved in EB-2013-0321.

6 Actual regulatory return on equity in col. (d) as per Table 2, line 13, col. (c).

Numbers may not calculate due to rounding.

Submitted: July 7, 2015

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 2
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2014

Line No.	Description	Note	Regulated Hydroelectric[1]	Nuclear	Total
			(a)	(b)	(c)
1	**Accounting EBIT (includes rounding)**	2	500.5	(13.1)	487.4
Accounting Expenses/Revenues not Included in Regulatory EBIT:					
2	**Add: Accretion on Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities**	2	N/A	[redacted]	[redacted]
3	**Deduct: Earnings/(Losses) on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds**	2	N/A	[redacted]	[redacted]
Differences Between Accounting and Regulatory Treatment:					
4	**Deduct: Shareholder Portion of Hydroelectric Incentive Mechanism Revenue**	3	[redacted]	N/A	[redacted]
5	**Deduct: Shareholder Portion of Heavy Water Sales Net of Costs**	4	N/A	[redacted]	[redacted]
6	**Add: Pickering Life Extension Depreciation Variance Account Impact on EBIT**	5	N/A	(7.7)	(7.7)
7	**Add: Accounting Capital Tax on Regulated Assets**		[redacted]	[redacted]	[redacted]
8	**Regulatory EBIT** (lines 1+2-3-4-5+6+7)		492.7	27.1	519.8
Deemed Cost of Capital:					
9	**Deduct: Cost of Deemed Debt for Regulated Assets**	6	202.2	62.3	264.5
10	**Deduct: Cost Related to UNL/ARC Adjustment**	6	N/A	74.6	74.6
11	**Add: Cost of Capital Variance and Deferral Account Additions**	7	84.0	6.1	90.1
12	**Regulatory EBT** (line 8 - line 9 - line 10 + line 11)		374.5	(103.7)	270.8
Determination of Regulatory Return on Equity:					
13	**Deduct: Regulatory Income Taxes on Regulated Assets**	8	6.7	(26.8)	(20.1)
14	**Regulatory Return on Equity** (line 12 - line 13)		367.8	(76.9)	290.9

See Table 2a for notes

Numbers may not calculate due to rounding.

Submitted: July 7, 2015

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 2a
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2014
Notes to Table 2

Notes:

1 Newly regulated hydroelectric facilities are included for the full year beginning on January 1, 2014, as presented in the EB-2013-0321 Payment Amounts Order. For the period January 1, 2014 to October 31, 2014, revenues for newly regulated hydroelectric production are based on electricity market prices, which these facilities received prior to the implementation of the EB-2013-0321 payment amounts effective November 1, 2014.

2 Actual amounts on lines 1, 2, and 3 are determined in accordance with United States Generally Accepted Accounting Principles ("US GAAP"), as approved by the OEB for use by OPG for regulatory accounting, reporting and rate-making purposes. These amounts are determined using the same methodology as reflected in OPG's 2014 audited consolidated financial statements, and the audited financial statements for the prescribed facilities filed in EB-2013-0321.

3 During 2014, hydroelectric incentive mechanism ("HIM") revenue is earned pursuant to the mechanism approved by the OEB in EB-2010-0008 and EB-2013-0321. The shareholder portion of HIM revenue is comprised of 50% of actual revenue for January 1, 2014 to October 31, 2014 pursuant to the sharing mechanism approved in EB-2010-0008, and nil for November 1, 2014 to December 31, 2014. The shareholder portion for November 1, 2014 to December 31, 2014 is nil because OPG's actual HIM revenues during this period were less than the amount applied by the OEB in reducing the revenue requirement in EB-2013-0321.

[redacted]

4 Heavy water sales net of costs are applied by the OEB as a reduction to OPG's nuclear revenue requirement. In EB-2010-0008, the OEB approved a sharing mechanism for heavy water sales net of costs between OPG and ratepayers. The shareholder portion of heavy water sales net of costs represents the difference between the actual sales net of costs in 2014 and the sum of: (i) 10/12 of the average revenue requirement reduction for 2011 and 2012 as per EB-2010-0008 Payment Amounts Order, and and (ii) 2/12 of the revenue requirement reduction for 2014 reflected in the EB-2013-0321 Payment Amounts Order.

5 The Pickering Life Extension Depreciation Variance Account Impact on EBIT represents the regulatory EBIT impact of the January 1, 2014 to October 31, 2014 depreciation addition and amortization recorded in the account. In accordance with US GAAP, these impacts were not recognized in OPG's 2014 audited consolidated financial statements and therefore are not reflected in Accounting EBIT at line 1. The amount of the adjustment is computed as follows: the amortization credit of $31.3M (shown in EB-2014-0370 Ex. H1-1-2 Table 1b, line 28, col. (c)) less the $39.0M depreciation expense credit (shown in EB-2014-0370 Ex. H1-1-2 Table 1b, line 28, col. (b)) recorded in the variance account during the January 1, 2014 to October 31, 2014 period.

6 Cost related to deemed debt and UNL/ARC adjustment for 2014 is allocated to Regulated Hydroelectric and Nuclear based on actual rate base, using the same methodology as applied in EB-2013-0321, as follows:

Table to Note 6 ($M)

Line No.	Item	Regulated Hydroelectric (see Note 1 above)	Nuclear
		(a)	(b)
1a	Interest Rate (Table 1, line 4, col. (c))	5.03%	5.03%
2a	Actual Rate Base (Table 1, line 8, col. (a))	7,547.5	3,714.4
3a	ARC / UNL Adjustment (Table 1, line 7, col. (a))	N/A	1,389.4
4a	Rate Base Financed by Capital Structure	7,547.5	2,325.0
	(line 2a - line 3a)		
5a	Debt Ratio (Table 1, line 4, col. (b))	53.3%	53.3%
6a	Deemed Debt (line 4a x line 5a)	4,022.8	1,239.2
7a	Cost of Deemed Debt for Regulated Assets	202.2	62.3
	(line 1a x line 6a)		
8a	Cost Related to UNL/ARC Adjustment	N/A	74.6
	(Table 1, line 7, col. (c) x line 3a)		

7 The amount represents the sum of the cost of capital additions to the Capacity Refurbishment Variance Account ("CRVA") recorded by OPG during 2014 and the $0.6M return on rate base credit component of the 2014 additions to the Nuclear Liability Deferral Account (found at EB-2014-0370 Ex. H1-1-2, Table 10, col. (b), line 4). For the Regulated Hydroelectric, the CRVA amount represents $82.9M for the Niagara Tunnel Project shown at EB-2014-0370 Ex. H1-1-2, Table 7, col. (c), line 3 plus $1.0M for other qualifying hydroelectric projects reflected in EB-2014-0370 Ex. H1-1-2, Table 7, col. (c), lines 9-13. For Nuclear, the CRVA amount represents the Darlington Refurbishment Project cost of capital addition reflected in EB-2014-0370 Ex. H1-1-2, Table 12, col. (d), lines 22 and 33.

8 The amount of regulatory income taxes is determined based on Regulatory EBT at line 12, using the methodology for the calculation of regulatory income taxes in the EB-2013-0321 Payment Amounts Order, as adjusted to reflect the inclusion of income tax amounts in certain deferral and variance accounts.

Numbers may not calculate due to rounding.

Submitted: June 30, 2016

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 1
Summary of Actual Capitalization and Cost of Capital[1]
Year Ended December 31, 2015

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
1	**Short-term Debt**	2, 3	45.5	0.5%	1.01%	2.8
2	**Existing Long-term Debt**	2	2,590.0	26.4%	5.18%	134.0
3	**Other Long-term Debt Provision**	2, 4	2,765.3	28.2%	5.18%	143.1
4	**Total Debt**	5	5,400.8	55.0%	5.18%	279.9
5	**Common Equity**	5, 6	4,418.9	45.0%	3.63%	160.3
6	**Rate Base Financed by Capital Structure**	5	9,819.7	88.2%	4.48%	440.2
7	**Adjustment for Lesser of UNL or ARC**	2	1,308.7	11.8%	5.37%	70.3
8	**Rate Base**	2	11,128.4	100.0%	4.59%	510.5

Notes:

1 As shown in EB-2016-0152 Ex. C1-1-1, Table 7, as updated for the actual 2015 income tax return completed in June 2016.

2 Amounts in cols. (a) and (d) and the cost rates in col. (c) are determined using the same methodologies as applied in EB-2013-0321.

3 The cost of short-term debt includes interest at the cost rate shown in col. (c) plus an allocation of the actual credit facility cost.

4 Debt required to balance capital structure with actual rate base.

5 Capital structure as approved by the OEB in EB-2013-0321.

6 Actual regulatory return on equity in col. (d) from Table 2, line 13, col. (c).

Numbers may not calculate due to rounding.

Submitted: June 30, 2016

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 2
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2015

Line No.	Description	Note	Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
1	**Accounting EBIT (includes rounding)**	1	648.2	(235.2)	413.0
Accounting Expenses/Revenues not Included in Regulatory EBIT:					
2	**Add: Accretion on Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities**	1, 8	N/A	[redacted]	[redacted]
3	**Deduct: Earnings/(Losses) on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds**	1, 9	N/A	[redacted]	[redacted]
Differences Between Accounting and Regulatory Treatment:					
4	**Deduct: Shareholder Portion of Hydroelectric Incentive Mechanism Revenue**	2	[redacted]	N/A	[redacted]
5	**Deduct: Shareholder Portion of Heavy Water Sales Net of Costs**	3	N/A	[redacted]	[redacted]
6	**Deduct: Amortization of Return on Equity Components of Variance and Deferral Account Balances**	4	34.8	2.2	37.0
7	**Regulatory EBIT** (lines 1+2-3-4-5-6)		613.5	(101.7)	511.7
Deemed Cost of Capital:					
8	**Deduct: Cost of Deemed Debt for Regulated Assets**	5	213.1	66.9	279.9
9	**Deduct: Cost Related to UNL/ARC Adjustment**	5	N/A	70.3	70.3
10	**Add: Cost of Capital Variance and Deferral Account Additions**	6	0.4	0.2	0.7
11	**Regulatory EBT** (line 7 - line 8 - line 9 + line 10)		400.9	(238.7)	162.2
Determination of Regulatory Return on Equity:					
12	**Deduct: Regulatory Income Taxes on Regulated Assets**	7	14.1	(12.2)	1.9
13	**Regulatory Return on Equity** (line 11 - line 12)		386.8	(226.5)	160.3

See Table 2a for notes

Numbers may not calculate due to rounding.

Submitted: June 30, 2016

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 2a
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2015
Notes to Table 2

Notes:

1 Actual amounts on lines 1, 2, and 3 are determined in accordance with United States Generally Accepted Accounting Principles (US GAAP), as approved by the OEB for use by OPG for regulatory accounting, reporting and rate-making purposes. These amounts are as reflected in the 2015 audited financial statements for the prescribed facilities, found at EB-2016-0152 Ex. A2-1-1, Attachment 5. Nuclear accounting EBIT at line 1 consists of Nuclear Generation and Nuclear Waste Management segments in the 2015 audited financial statements for the prescribed facilities.

2 During 2015, hydroelectric incentive mechanism (HIM) revenue was earned pursuant to the mechanism approved by the OEB in EB-2013-0321.
[redacted]

3 Heavy water sales net of costs are applied by the OEB as a reduction to OPG's nuclear revenue requirement. In EB-2010-0008, the OEB approved a sharing mechanism for heavy water sales net of costs between OPG and ratepayers. The shareholder portion of heavy water sales net of costs represents the excess, if any, of the actual sales net of costs in 2015 over the revenue requirement reduction for 2015 reflected in the EB-2013-0321 Payment Amounts Order.

4 Amounts represent differences between the cost of capital additions recognized in the variance and deferral accounts, and the corresponding regulatory assets reflected in the US GAAP financial statements. In accordance with US GAAP, OPG limits the portion of cost of capital additions recognized as a regulatory asset in the financial statements to amounts calculated using the average rate of capitalized interest applied by OPG to construction and development in progress balances.

5 Costs related to deemed debt and UNL/ARC adjustment for 2015 are allocated to Regulated Hydroelectric and Nuclear based on actual rate base, using the same methodology applied in EB-2013-0321, as follows:

Table to Note 5 ($M)

Line No.	Item	Regulated Hydroelectric	Nuclear
		(a)	(b)
1a	Interest Rate (Table 1, line 4, col. (c))	5.18%	5.18%
2a	Actual Rate Base (Table 1, line 8, col. (a))	7,473.2	3,655.2
3a	ARC / UNL Adjustment (Table 1, line 7, col. (a))	N/A	1,308.7
4a	Rate Base Financed by Capital Structure	7,473.2	2,346.5
	(line 2a - line 3a)		
5a	Debt Ratio (Table 1, line 4, col. (b))	55.0%	55.0%
6a	Deemed Debt (line 4a x line 5a)	4,110.3	1,290.6
7a	Cost of Deemed Debt for Regulated Assets	213.1	66.9
	(line 1a x line 6a)		
8a	Cost Related to UNL/ARC Adjustment	N/A	70.3
	(Table 1, line 7, col. (c) x line 3a)		

6 The amount represents the cost of capital additions to the Capacity Refurbishment Variance Account recorded by OPG in 2015, as reflected in EB-2016-0152 Ex. H1-1-1, Table 11, col. (a), lines 22 and 33 and Ex. H1-1-1, Table 7, col. (a), lines 9 and 10.

7 The amount of regulatory income taxes is determined based on Regulatory EBT at line 11, using the methodology for calculating regulatory income taxes applied in EB-2013-0321, as adjusted to reflect the inclusion of income tax amounts in certain deferral and variance accounts, and reflecting the actual 2015 income tax return completed in June 2016.

[redacted]

[redacted]

Numbers may not calculate due to rounding.

Submitted: June 30, 2017

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 1
Summary of Actual Capitalization and Cost of Capital
Year Ended December 31, 2016

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
1	**Short-term Debt**	1, 2	8.0	0.1%	0.79%	2.4
2	**Existing Long-term Debt**	1	3,005.4	30.0%	5.23%	157.3
3	**Other Long-term Debt Provision**	1, 3	2,487.4	24.9%	5.23%	130.1
4	**Total Debt**	4	5,500.9	55.0%	5.27%	289.8
5	**Common Equity**	4, 5	4,500.7	45.0%	3.80%	171.0
6	**Rate Base Financed by Capital Structure**	4	10,001.5	92.4%	4.61%	460.9
7	**Adjustment for Lesser of UNL or ARC**	1	825.7	7.6%	5.11%	42.2
8	**Rate Base**	1	10,827.2	100.0%	4.65%	503.1

Notes:
1 Amounts in cols. (a) and (d) and the cost rates in col. (c) are determined using the same methodologies as applied in EB-2013-0321.
2 The cost of short-term debt includes interest at the cost rate shown in col. (c) plus an allocation of the actual credit facility cost.
3 Debt required to balance capital structure with actual rate base.
4 Capital structure as approved by the OEB in EB-2013-0321.
5 Actual regulatory return on equity in col. (d) from Table 2, line 13, col. (c).

Numbers may not calculate due to rounding.

Submitted: June 30, 2017

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 2
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2016

Line No.	Description	Note	Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
1	**Accounting EBIT (includes rounding)**	1	642.0	(222.0)	420.0
Accounting Expenses/Revenues not Included in Regulatory EBIT:					
2	**Add: Accretion on Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities**	1	N/A	[redacted]	[redacted]
3	**Deduct: Earnings/(Losses) on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds**	1	N/A	[redacted]	[redacted]
Differences Between Accounting and Regulatory Treatment:					
4	**Deduct: Shareholder Portion of Hydroelectric Incentive Mechanism Revenue**	2	[redacted]	N/A	[redacted]
5	**Deduct: Shareholder Portion of Heavy Water Sales Net of Costs**	3	N/A	[redacted]	[redacted]
6	**Deduct: Amortization of Return on Equity Components of Variance and Deferral Account Balances**	4	18.1	1.5	19.6
7	**Regulatory EBIT** (lines 1+2-3-4-5-6)		623.9	(97.3)	526.6
Deemed Cost of Capital:					
8	**Deduct: Cost of Deemed Debt for Regulated Assets**	5	215.1	74.7	289.8
9	**Deduct: Cost Related to UNL/ARC Adjustment**	5	N/A	42.2	42.2
10	**Add: Cost of Capital Variance and Deferral Account Additions**	6	3.7	(12.3)	(8.6)
11	**Regulatory EBT** (line 7 - line 8 - line 9 + line 10)		412.5	(226.5)	185.9
Determination of Regulatory Return on Equity:					
12	**Deduct: Regulatory Income Taxes on Regulated Assets**	7	18.4	(3.5)	14.9
13	**Regulatory Return on Equity** (line 11 - line 12)		394.1	(223.0)	171.0

See Table 2a for notes

Numbers may not calculate due to rounding.

Submitted: June 30, 2017

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 2a
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2016
Notes to Table 2

Notes:

1 Actual amounts on lines 1, 2, and 3 are determined in accordance with United States Generally Accepted Accounting Principles (US GAAP), as approved by the OEB for use by OPG for regulatory accounting, reporting and rate-making purposes. These amounts are determined using the same methodology as reflected in the 2015 audited financial statements for OPG's prescribed facilities filed in EB-2016-0152 Ex. A2-1-1, Attachment 5, and the audited financial statements for the prescribed facilities filed in EB-2013-0321.

2 During 2016, hydroelectric incentive mechanism (HIM) revenue was earned pursuant to the mechanism approved by the OEB in EB-2013-0321.

[redacted]

[redacted]

3 Heavy water sales net of costs are applied by the OEB as a reduction to OPG's nuclear revenue requirement. In EB-2010-0008, the OEB approved a sharing mechanism for heavy water sales net of costs between OPG and ratepayers. The shareholder portion of heavy water sales net of costs represents the excess, if any, of the actual sales net of costs in 2016 over the average annual revenue requirement reduction for 2014 and 2015 reflected in the EB-2013-0321 Payment Amounts Order.

4 Amounts represent differences between the cost of capital additions recognized in the variance and deferral accounts, and the corresponding regulatory assets reflected in the US GAAP financial statements. In accordance with US GAAP, OPG limits the portion of cost of capital additions recognized as a regulatory asset in the financial statements to amounts calculated using the average rate of capitalized interest applied by OPG to construction and development in progress balances.

5 Costs related to deemed debt and UNL/ARC adjustment for 2016 are allocated to Regulated Hydroelectric and Nuclear based on actual rate base, using the same methodology applied in EB-2013-0321, as follows:

Table to Note 5 ($M)

Line No.	Item	Regulated Hydroelectric	Nuclear
		(a)	(b)
1a	Interest Rate (Table 1, line 4, col. (c))	5.27%	5.27%
2a	Actual Rate Base (Table 1, line 8, col. (a))	7,423.6	3,403.6
3a	ARC / UNL Adjustment (Table 1, line 7, col. (a))	N/A	825.7
4a	Rate Base Financed by Capital Structure	7,423.6	2,577.9
	(line 2a - line 3a)		
5a	Debt Ratio (Table 1, line 4, col. (b))	55.0%	55.0%
6a	Deemed Debt (line 4a x line 5a)	4,083.0	1,417.9
7a	Cost of Deemed Debt for Regulated Assets	215.1	74.7
	(line 1a x line 6a)		
8a	Cost Related to UNL/ARC Adjustment	N/A	42.2
	(Table 1, line 7, col. (c) x line 3a)		

6 The amounts represent the cost of capital additions to the Capacity Refurbishment Variance Account and the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account recorded in 2016, as well as the return on rate base credit recorded in the Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account in 2016.

7 The amount of regulatory income taxes is determined based on Regulatory EBT at line 11, using the methodology for calculating regulatory income taxes applied in EB-2013-0321, as adjusted to reflect the inclusion of income tax amounts in certain deferral and variance accounts (i.e. the impact of tax additions and deductions that represent items for which the tax cost or benefit is being passed on to ratepayers through deferral and variance accounts), and reflecting the actual 2016 income tax return completed in June 2017.

Numbers may not add due to rounding.

Table 10
Capitalization and Cost of Capital
Summary of Capitalization and Actual Cost of Capital
Calendar Year Ending December 31, 2017

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	38.8	0.4%	1.10%	2.8
2	**Existing/Planned Long-Term Debt**	2	3,016.0	28.8%	4.99%	150.4
3	**Other Long-Term Debt Provision**	3	2,705.4	25.8%	4.99%	134.9
4	**Total Debt**	4	5,760.3	55.0%	5.00%	288.1
5	**Common Equity**	4	4,712.9	45.0%	6.02%	283.7
6	**Rate Base Financed by Capital Structure**	5	10,473.2	95.4%	5.46%	571.8
7	**Adjustment for Lesser of UNL or ARC**	5, 6	505.1	4.6%	4.95%	25.0
8	**Rate Base**		10,978.3	100%	5.44%	596.8

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. C1-1-2 Table 3, line 46.

3 Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.

4 Capital Structure as approved in EB-2016-0152 and EB-2013-0321. Return on Equity in col. (d) determined using the reconciliation approach discussed in EB-2013-0321 Ex. C1-1-1 Section 4.2, starting with the financial results for OPG's prescribed assets calculated in accordance with US GAAP.

5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from C2-1-1 Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

Numbers may not add due to rounding.

Table 1
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2017

Line No.	Description	Note	Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
1	**Accounting EBIT (includes rounding)**	1	611.6	(115.4)	496.3
Accounting Expenses/Revenues not Included in Regulatory EBIT:					
2	**Add: Accretion on Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities**	1	N/A	[redacted]	
3	**Deduct: Earnings/(Losses) on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds**	1	N/A		
Differences Between Accounting and Regulatory Treatment:					
4	**Deduct: Shareholder Portion of Hydroelectric Incentive Mechanism Revenue**	2	[redacted]	N/A	[redacted]
5	**Deduct: Shareholder Portion of Heavy Water Sales Net of Costs**	3	N/A	[redacted]	
6	**Regulatory EBIT** (lines 1+2-3-4-5)		611.6	(28.3)	583.3
Deemed Cost of Capital:					
7	**Deduct: Cost of Deemed Debt for Regulated Assets**	4	203.1	85.0	288.0
8	**Deduct: Cost Related to UNL/ARC Adjustment**	4	N/A	25.0	25.0
9	**Add: Cost of Capital Variance and Deferral Account Additions**	5	4.1	6.7	10.8
10	**Regulatory EBT** (line 6 - line 7 - line 8 + line 9)		412.6	(131.6)	281.1
Determination of Regulatory Return on Equity:					
11	**Deduct: Regulatory Income Taxes on Regulated Assets**	6	10.6	(13.2)	(2.7)
12	**Regulatory Return on Equity** (line 10 - line 11)		402.0	(118.3)	283.7

See Table 1a for notes

Numbers may not add due to rounding.

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Table 1a
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2017
Notes to Table 1a

Notes:

1 Actual amounts on lines 1, 2, and 3 are determined in accordance with United States Generally Accepted Accounting Principles (US GAAP), as approved by the OEB for use by OPG for regulatory accounting, reporting and rate-making purposes. These amounts are determined using the same methodology as reflected in the 2015 audited financial statements for OPG's prescribed facilities filed in EB-2016-0152 Ex. A2-1-1, Attachment 5, and the audited financial statements for the prescribed facilities filed in EB-2013-0321 Ex. A2-1-1, Attachment 2.

2 During 2017, hydroelectric incentive mechanism (HIM) revenue was earned pursuant to the mechanism approved by the OEB in EB-2013-0321 and continued in EB-2016-0152.

[redacted]

3 Heavy water sales net of costs are applied by the OEB as a reduction to OPG's nuclear revenue requirement. In EB-2010-0008, the OEB approved a sharing mechanism for heavy water sales net of costs between OPG and ratepayers. The shareholder portion of heavy water sales net of costs represents the excess, if any, of the actual sales net of costs in 2017 over the sum of: (i) 5/12 of the average revenue requirement reduction for 2014 and 2015 reflected in the EB-2013-0321 Payment Amounts Order, and (ii) 7/12 of the revenue requirement reduction for 2017 reflected in the EB-2016-0152 Payment Amounts Order.

4 Costs related to deemed debt and UNL/ARC adjustment for 2017 are allocated to Regulated Hydroelectric and Nuclear based on actual rate base, using the same methodology applied in EB-2013-0321 and EB-2016-0152, as follows:

Table to Note 4 ($M)

Line No.	Item	Regulated Hydroelectric	Nuclear
		(a)	(b)
1a	Interest Rate (Table 1, line 4, col. (c))	5.00%	5.00%
2a	Actual Rate Base (Ex. C-1-1, Table 10, line 8, col. (a))	7,383.3	3,595.0
3a	ARC / UNL Adjustment (Ex. C-1-1, Table 10, line 7, col. (a))	N/A	505.1
4a	Rate Base Financed by Capital Structure	7,383.3	3,089.9
	(line 2a - line 3a)		
5a	Debt Ratio (Ex. C-1-1, Table 10, line 4, col. (b))	55.0%	55.0%
6a	Deemed Debt (line 4a x line 5a)	4,060.8	1,699.4
7a	Cost of Deemed Debt for Regulated Assets	203.1	85.0
	(line 1a x line 6a)		
8a	Cost Related to UNL/ARC Adjustment	N/A	25.0
	(Ex. C-1-1, Table 10, line 7, col. (c) x line 3a)		

5 The amounts represent the cost of capital additions to the Capacity Refurbishment Variance Account, the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account, the Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account in 2017 and the Nuclear Liability Deferral Account recorded in 2017.

6 The amount of regulatory income taxes is determined based on Regulatory EBT at line 10, using the methodology for calculating regulatory income taxes applied in EB-2013-0321 and EB-2016-0152, as adjusted to reflect the inclusion of income tax amounts in certain deferral and variance accounts (i.e. the impact of tax additions and deductions that represent items for which the tax cost or benefit is being passed on to ratepayers through deferral and variance accounts), and reflecting the actual 2017 income tax return completed in June 2018. Consistent with OPG's EB-2016-0152 Reply Argument, p.173, footnote 94, starting in 2017, the regulatory income tax calculation reflects Scientific Research & Experimental Development investment tax credits in the amount earned for the year (at the applicable accounting recognition percentage).

Numbers may not add due to rounding.

Table 9
Capitalization and Cost of Capital
Summary of Capitalization and Actual Cost of Capital
Calendar Year Ending December 31, 2018

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	86.2	0.8%	1.67%	3.7
2	**Existing/Planned Long-Term Debt**	2	3,783.4	35.1%	4.48%	169.5
3	**Other Long-Term Debt Provision**	3	2,056.6	19.1%	4.48%	92.1
4	**Total Debt**	4	5,926.2	55.0%	4.48%	265.3
5	**Common Equity**	4	4,848.7	45.0%	10.72%	519.8
6	**Rate Base Financed by Capital Structure**	5	10,775.0	95.0%	7.29%	785.1
7	**Adjustment for Lesser of UNL or ARC**	5, 6	570.6	5.0%	4.93%	28.1
8	**Rate Base**		11,345.6	100%	7.17%	813.2

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. C1-1-2 Table 4, line 45.

3 Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.

4 Capital Structure as approved in EB-2016-0152. Return on Equity in col. (d) determined using the reconciliation approach discussed in EB-2013-0321 Ex. C1-1-1 Section 4.2, starting with the financial results for OPG's prescribed assets calculated in accordance with US GAAP.

5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from C2-1-1 Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

Numbers may not add due to rounding.

Table 2
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2018

Line No.	Description	Note	Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
1	**Accounting EBIT (includes rounding)**	1	596.7	233.6	830.3
Accounting Expenses/Revenues not Included in Regulatory EBIT:					
2	**Add: Accretion on Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities**	1	N/A	[redacted]	[redacted]
3	**Deduct: Earnings/(Losses) on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds**	1	N/A		
Differences Between Accounting and Regulatory Treatment:					
4	**Deduct: Shareholder Portion of Hydroelectric Incentive Mechanism Revenue**	2	[redacted]	N/A	[redacted]
5	**Deduct: Shareholder Portion of Heavy Water Sales Net of Costs**	3	N/A	[redacted]	
6	**Deduct: Amortization of Return on Equity Components of Variance and Deferral Account Balances**	4	0.0	0.1	0.1
7	**Regulatory EBIT** (lines 1+2-3-4-5-6)		596.7	278.9	875.7
Deemed Cost of Capital:					
8	**Deduct: Cost of Deemed Debt for Regulated Assets**	5	182.0	83.3	265.3
9	**Deduct: Cost Related to UNL/ARC Adjustment**	5	N/A	28.1	28.1
10	**Add: Cost of Capital Variance and Deferral Account Additions**	6	7.2	27.3	34.5
11	**Regulatory EBT** (line 7 - line 8 - line 9 + line 10)		421.9	194.8	616.8
Determination of Regulatory Return on Equity:					
12	**Deduct: Regulatory Income Taxes on Regulated Assets**	7	87.7	9.3	97.0
13	**Regulatory Return on Equity** (line 11 - line 12)		334.2	185.5	519.8

See Table 2a for notes

Numbers may not add due to rounding.

Table 2a
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2018
Notes to Table 2

Notes:

1 Actual amounts on lines 1, 2, and 3 are determined in accordance with United States Generally Accepted Accounting Principles (US GAAP), as approved by the OEB for use by OPG for regulatory accounting, reporting and rate-making purposes. These amounts are determined using the same methodology as reflected in the 2015 audited financial statements for OPG's prescribed facilities filed in EB-2016-0152 Ex. A2-1-1, Attachment 5.

2 During 2018, hydroelectric incentive mechanism (HIM) revenue was earned pursuant to the mechanism approved by the OEB in EB-2013-0321 and continued in EB-2016-0152.

[redacted]

3 Heavy water sales net of costs are applied by the OEB as a reduction to OPG's nuclear revenue requirement. In EB-2010-0008, the OEB approved a sharing mechanism for heavy water sales net of costs between OPG and ratepayers. The shareholder portion of heavy water sales net of costs represents the excess, if any, of the actual sales net of costs in 2018 reflected in the EB-2016-0152 Payment Amounts Order.

4 Amounts represent differences between the cost of capital additions recognized in the variance and deferral accounts, and the corresponding regulatory assets reflected in the US GAAP financial statements. In accordance with US GAAP, OPG limits the portion of cost of capital additions recognized as a regulatory asset in the financial statements to amounts calculated using the average rate of capitalized interest applied by OPG to construction and development in progress balances.

5 Costs related to deemed debt and UNL/ARC adjustment for 2018 are allocated to Regulated Hydroelectric and Nuclear based on actual rate base, using the same methodology applied in EB-2016-0152, as follows:

Table to Note 4 ($M)

Line No.	Item	Regulated Hydroelectric	Nuclear
		(a)	(b)
1a	Interest Rate (Ex. C-1-1, Table 9, line 4, col. (c))	4.48%	4.48%
2a	Actual Rate Base (Ex. C-1-1, Table 9, line 8, col. (a))	7,391.2	3,954.4
3a	ARC / UNL Adjustment (Ex. C-1-1, Table 9, line 7, col. (a))	N/A	570.6
4a	Rate Base Financed by Capital Structure	7,391.2	3,383.8
	(line 2a - line 3a)		
5a	Debt Ratio (Ex. C-1-1, Table 9, line 4, col. (b))	55.0%	55.0%
6a	Deemed Debt (line 4a x line 5a)	4,065.2	1,861.1
7a	Cost of Deemed Debt for Regulated Assets	182.0	83.3
	(line 1a x line 6a)		
8a	Cost Related to UNL/ARC Adjustment	N/A	28.1
	(Ex. C-1-1, Table 9, line 7, col. (c) x line 3a)		

6 The amounts represent the cost of capital additions to the Capacity Refurbishment Variance Account, the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account, and the Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2017) Deferral Account recorded in 2018.

7 The amount of regulatory income taxes is determined based on Regulatory EBT at line 11, using the methodology for calculating regulatory income taxes applied in EB-2016-0152, as adjusted to reflect the inclusion of income tax amounts in certain deferral and variance accounts (i.e. the impact of tax additions and deductions that represent items for which the tax cost or benefit is being passed on to ratepayers through deferral and variance accounts) and to exclude the benefit of the 2018 nuclear tax loss forecasted in EB-2016-0152 to be carried forward beyond the 2017-2021 period. The amount of regulatory income taxes reflects the actual 2018 income tax return completed in June 2019. Consistent with OPG's EB-2016-0152 Reply Argument, p.173, footnote 94, starting in 2017, the regulatory income tax calculation reflects Scientific Research & Experimental Development investment tax credits in the amount earned for the year (at the applicable accounting recognition percentage).

Numbers may not add due to rounding.

Table 8
Capitalization and Cost of Capital
Summary of Capitalization and Actual Cost of Capital
Calendar Year Ending December 31, 2019

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	139.9	1.3%	1.96%	5.1
2	**Existing/Planned Long-Term Debt**	2	3,962.3	36.0%	4.33%	171.4
3	**Other Long-Term Debt Provision**	3	1,946.0	17.7%	4.33%	84.2
4	**Total Debt**	4	6,048.2	55.0%	4.31%	260.7
5	**Common Equity**	4	4,948.5	45.0%	15.72%	778.1
6	**Rate Base Financed by Capital Structure**	5	10,996.7	95.7%	9.45%	1,038.8
7	**Adjustment for Lesser of UNL or ARC**	5, 6	488.5	4.3%	4.90%	23.9
8	**Rate Base**		11,485.1	100%	9.25%	1,062.7

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. C1-1-2 Table 5, line 44.

3 Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.

4 Capital Structure as approved in EB-2016-0152. Return on Equity in col. (d) determined using the reconciliation approach discussed in EB-2013-0321 Ex. C1-1-1 Section 4.2, starting with the financial results for OPG's prescribed assets calculated in accordance with US GAAP.

5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from C2-1-1, Table 2, line 30. Cost rate from Ex. C2-1-1, Section 4.1.4.

Numbers may not add due to rounding.

Table 3
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2019

Line No.	Description	Note	Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
1	**Accounting EBIT (includes rounding)**	1	620.3	524.7	1,145.0
Accounting Expenses/Revenues not Included in Regulatory EBIT:					
2	**Add: Accretion on Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities**	1	N/A	[redacted]	
3	**Deduct: Earnings/(Losses) on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds**	1	N/A		
Differences Between Accounting and Regulatory Treatment:					
4	**Deduct: Shareholder Portion of Hydroelectric Incentive Mechanism Revenue**	2	[redacted]	N/A	0.0
5	**Deduct: Shareholder Portion of Heavy Water Sales Net of Costs**	3	N/A	[redacted]	
6	**Deduct: Amortization of Return on Equity Components of Variance and Deferral Account Balances**	4	0.4	0.0	0.4
7	**Regulatory EBIT** (lines 1+2-3-4-5-6)		619.9	572.3	1,192.2
Deemed Cost of Capital:					
8	**Deduct: Cost of Deemed Debt for Regulated Assets**	5	176.3	84.4	260.7
9	**Deduct: Cost Related to UNL/ARC Adjustment**	5	N/A	24.1	24.1
10	**Add: Cost of Capital Variance and Deferral Account Additions**	6	11.0	36.3	47.3
11	**Regulatory EBT** (line 7 - line 8 - line 9 + line 10)		454.6	500.1	954.7
Determination of Regulatory Return on Equity:					
12	**Deduct: Regulatory Income Taxes on Regulated Assets**	7	79.7	96.9	176.6
13	**Regulatory Return on Equity** (line 11 - line 12)		374.8	403.3	778.1

See Table 3a for notes

Numbers may not add due to rounding.

Table 3a
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2019
Notes to Table 3

Notes:

1 Actual amounts on lines 1, 2, and 3 are determined in accordance with United States Generally Accepted Accounting Principles (US GAAP), as approved by the OEB for use by OPG for regulatory accounting, reporting and rate-making purposes. These amounts are determined using the same methodology as reflected in the 2015 audited financial statements for OPG's prescribed facilities filed in EB-2016-0152 Ex. A2-1-1, Attachment 5.

2 During 2019, hydroelectric incentive mechanism (HIM) revenue was earned pursuant to the mechanism approved by the OEB in EB-2013-0321 and continued in EB-2016-0152.

[redacted]

3 Heavy water sales net of costs are applied by the OEB as a reduction to OPG's nuclear revenue requirement. In EB-2010-0008, the OEB approved a sharing mechanism for heavy water sales net of costs between OPG and ratepayers. The shareholder portion of heavy water sales net of costs represents the excess, if any, of the actual sales net of costs in 2019 reflected in the EB-2016-0152 Payment Amounts Order.

4 Amounts represent differences between the cost of capital additions recognized in the variance and deferral accounts, and the corresponding regulatory assets reflected in the US GAAP financial statements. In accordance with US GAAP, OPG limits the portion of cost of capital additions recognized as a regulatory asset in the financial statements to amounts calculated using the average rate of capitalized interest applied by OPG to construction and development in progress balances.

5 Costs related to deemed debt and UNL/ARC adjustment for 2019 are allocated to Regulated Hydroelectric and Nuclear based on actual rate base, using the same methodology applied in EB-2016-0152, as follows:

Table to Note 4 ($M)

Line No.	Item	Regulated Hydroelectric	Nuclear
		(a)	(b)
1a	Interest Rate (Ex. C-1-1, Table 8, line 4, col. (c))	4.31%	4.31%
2a	Actual Rate Base (Ex. C-1-1, Table 8, line 8, col. (a))	7,437.9	4,047.2
3a	ARC / UNL Adjustment (Ex. C-1-1, Table 8, line 7, col. (a))	N/A	488.5
4a	Rate Base Financed by Capital Structure	7,437.9	3,558.8
	(line 2a - line 3a)		
5a	Debt Ratio (Ex. C-1-1, Table 8, line 4, col. (b))	55.0%	55.0%
6a	Deemed Debt (line 4a x line 5a)	4,090.8	1,957.3
7a	Cost of Deemed Debt for Regulated Assets	176.3	84.4
	(line 1a x line 6a)		
8a	Cost Related to UNL/ARC Adjustment	N/A	24.1
	(Ex. C-1-1, Table 8, line 7, col. (c) x line 3a)		

6 The amounts represent the cost of capital additions to the Capacity Refurbishment Variance Account, the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account, and the Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2017) Deferral Account recorded in 2019.

7 The amount of regulatory income taxes is determined based on Regulatory EBT at line 11, using the methodology for calculating regulatory income taxes applied in EB-2016-0152, as adjusted to reflect the inclusion of income tax amounts in certain deferral and variance accounts (i.e. the impact of tax additions and deductions that represent items for which the tax cost or benefit is being passed on to ratepayers through deferral and variance accounts) and to exclude the benefit of the 2019 nuclear tax loss forecasted in EB-2016-0152 to be carried forward beyond the 2017-2021 period. The amount of regulatory income taxes reflects the actual 2019 income tax return completed in June 2020. Consistent with OPG's EB-2016-0152 Reply Argument, p.173, footnote 94, starting in 2017, the regulatory income tax calculation reflects Scientific Research & Experimental Development investment tax credits in the amount earned for the year (at the applicable accounting recognition percentage).

Numbers may not add due to rounding.

Submitted: July 30, 2021

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 1
Summary of Actual Capitalization and Cost of Capital[1]
Year Ended December 31, 2020

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
1	**Short-term Debt**	2, 3	190.1	1.3%	0.70%	4.7
2	**Existing Long-term Debt**	2	3,868.2	27.4%	4.01%	155.3
3	**Other Long-term Debt Provision**	2, 4	3,692.5	26.2%	4.01%	148.2
4	**Total Debt**	5	7,750.9	55.0%	3.98%	308.3
5	**Common Equity**	5, 6	6,341.6	45.0%	17.22%	1,091.8
6	**Rate Base Financed by Capital Structure**	5	14,092.6	97.2%	9.93%	1,400.1
7	**Adjustment for Lesser of UNL or ARC**	2	406.3	2.8%	4.86%	19.7
8	**Rate Base**	2	14,498.9	100.0%	9.79%	1,419.8

Notes:
1 Represents the actual capitalization and cost of capital for the year ended December 31, 2020, reflecting the completed 2020 tax return and updated cash working capital amounts based on results from 2020. The forecast 2020 capitalization and cost of capital provided in EB-2020-0290, Ex. L-A1-2-Staff-002, Attachment 1, Table 5 were preliminary as noted.
2 Amounts in cols. (a) and (d) and the cost rates in col. (c) are determined using the same methodologies as applied in EB-2016-0152. Principal reflects the final 2020 allocation ratio based on OPG's 2020 financial results, updated from the preliminary allocation ratio used in EB-2020-0290, Ex. L-A1-2-Staff-002, Attachment 1, Table 5.
3 The cost of short-term debt includes interest at the cost rate shown in col. (c) plus an allocation of the actual credit facility cost.
4 Debt required to balance capital structure with actual rate base.
5 Capital structure as approved by the OEB in EB-2016-0152.
6 Actual regulatory return on equity in col. (d) from Table 2, line 13, col. (c).

Numbers may not add due to rounding.

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 2
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2020

Line No.	Description	Note	Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
1	**Accounting EBIT (includes rounding)**	1	661.6	989.0	1,650.6
	Accounting Expenses/Revenues not Included in Regulatory EBIT:				
2	**Add: Accretion on Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities**	1	N/A		
3	**Deduct: Earnings/(Losses) on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds**	1	N/A		
	Differences Between Accounting and Regulatory Treatment:				
4	**Deduct: Shareholder Portion of Hydroelectric Incentive Mechanism Revenue**	2		N/A	
5	**Deduct: Shareholder Portion of Heavy Water Sales Net of Costs**	3	N/A		
6	**Deduct: Amortization of Return on Equity Components of Variance and Deferral Account Balances**	4	0.4	0.0	0.4
7	**Regulatory EBIT** (lines 1+2-3-4-5-6)		661.2	1,032.7	1,693.9
	Deemed Cost of Capital:				
8	**Deduct: Cost of Deemed Debt for Regulated Assets**	5	163.5	144.7	308.3
9	**Deduct: Cost Related to UNL/ARC Adjustment**	5	N/A	19.7	19.7
10	**Add: Cost of Capital Variance and Deferral Account Additions**	6	16.1	(26.5)	(10.4)
11	**Regulatory EBT** (line 7 - line 8 - line 9 + line 10)		513.8	841.7	1,355.5
	Determination of Regulatory Return on Equity:				
12	**Deduct: Regulatory Income Taxes on Regulated Assets**	7	95.0	168.7	263.7
13	**Regulatory Return on Equity** (line 11 - line 12)		418.8	673.0	1,091.8

See Table 2a for notes

Numbers may not add due to rounding.

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 2a
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2020
Notes to Table 2

Notes:

1 Actual amounts on lines 1, 2, and 3 are determined in accordance with United States Generally Accepted Accounting Principles (US GAAP), as approved by the OEB for use by OPG for regulatory accounting, reporting and rate-making purposes. These amounts are determined using the same methodology as reflected in the audited financial statements for OPG's prescribed facilities filed in EB-2020-0290 Ex. A2-1-1, Attachment 2.

2 During 2020, hydroelectric incentive mechanism (HIM) revenue was earned pursuant to the mechanism approved by the OEB in EB-2013-0321 and continued in EB-2016-0152.

[redacted]

[redacted]

3 Heavy water sales net of costs are applied by the OEB as a reduction to OPG's nuclear revenue requirement. In EB-2010-0008, the OEB approved a sharing mechanism for heavy water sales net of costs between OPG and ratepayers. The shareholder portion of heavy water sales net of costs represents the excess, if any, of the actual sales net of costs in 2020 reflected in the EB-2016-0152 Payment Amounts Order.

4 Amounts represent differences between the cost of capital additions recognized in the variance and deferral accounts, and the corresponding regulatory assets reflected in the US GAAP financial statements. In accordance with US GAAP, OPG limits the portion of cost of capital additions recognized as a regulatory asset in the financial statements to amounts calculated using the average rate of capitalized interest applied by OPG to construction and development in progress balances.

5 Costs related to deemed debt and UNL/ARC adjustment for 2020 are allocated to Regulated Hydroelectric and Nuclear based on actual rate base, using the same methodology applied in EB-2016-0152, as follows:

Table to Note 5 ($M)

Line No.	Item	Regulated Hydroelectric	Nuclear
		(a)	(b)
1a	Interest Rate (Table 1, line 4, col. (c))	3.98%	3.98%
2a	Actual Rate Base (Table 1, line 8, col. (a))	7,476.1	7,022.8
3a	ARC / UNL Adjustment (Table 1, line 7, col. (a))	N/A	406.3
4a	Rate Base Financed by Capital Structure	7,476.1	6,616.5
	(line 2a - line 3a)		
5a	Debt Ratio (Table 1, line 4, col. (b))	55.0%	55.0%
6a	Deemed Debt (line 4a x line 5a)	4,111.8	3,639.1
7a	Cost of Deemed Debt for Regulated Assets	163.5	144.7
	(line 1a x line 6a)		
8a	Cost Related to UNL/ARC Adjustment	N/A	19.7
	(Table 1, line 7, col. (c) x line 3a)		

6 The amounts represent the cost of capital additions to the Capacity Refurbishment Variance Account, the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account, and the Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2017) Deferral Account recorded in 2020.

7 The amount of regulatory income taxes is determined based on Regulatory EBT at line 11, using the methodology for calculating regulatory income taxes applied in EB-2016-0152, as adjusted to reflect the inclusion of income tax amounts in certain deferral and variance accounts (i.e. the impact of tax additions and deductions that represent items for which the tax cost or benefit is being passed on to ratepayers through deferral and variance accounts) and to exclude the benefit of tax losses forecasted in EB-2016-0152 to be carried forward beyond the 2017-2021 period. The amount of regulatory income taxes reflects the 2020 income tax return completed in June 2021.

Numbers may not add due to rounding.

Submitted: July 29, 2022

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 1
Summary of Actual Capitalization and Cost of Capital
Year Ended December 31, 2021

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
1	**Short-term Debt**	1, 2	7.9	0.0%	0.21%	4.6
2	**Existing Long-term Debt**	1	3,638.6	22.7%	3.87%	140.9
3	**Other Long-term Debt Provision**	1, 3	5,176.8	32.3%	3.87%	200.4
4	**Total Debt**	4	8,823.2	55.0%	3.92%	345.9
5	**Common Equity**	4, 5	7,219.0	45.0%	10.79%	778.6
6	**Rate Base Financed by Capital Structure**	4	16,042.3	97.7%	7.01%	1,124.5
7	**Adjustment for Lesser of UNL or ARC**	1	376.2	2.3%	4.87%	18.3
8	**Rate Base**	1	16,418.4	100.0%	6.96%	1,142.8

Notes:
1 Amounts in cols. (a) and (d) and the cost rates in col. (c) are determined using the same methodologies as applied in EB-2016-0152.
2 The cost of short-term debt includes interest at the cost rate shown in col. (c) plus an allocation of the actual credit facility cost.
3 Debt required to balance capital structure with actual rate base.
4 Capital structure as approved by the OEB in EB-2016-0152.
5 Actual regulatory return on equity in col. (d) from Table 2, line 13, col. (c).

Numbers may not add due to rounding.

Submitted: July 29, 2022

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 2
Actual Regulatory Return on Equity ($M)[1]
Year Ended December 31, 2021

Line No.	Description	Note	Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
1	**Accounting EBIT (includes rounding)**	2	699.5	525.7	1,225.2
Accounting Expenses/Revenues not Included in Regulatory EBIT:					
2	**Add: Accretion on Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities**	2	N/A	[redacted]	[redacted]
3	**Deduct: Earnings/(Losses) on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds**	2	N/A	[redacted]	[redacted]
Differences Between Accounting and Regulatory Treatment:					
4	**Deduct: Shareholder Portion of Hydroelectric Incentive Mechanism Revenue**	3	[redacted]	N/A	[redacted]
5	**Deduct: Shareholder Portion of Heavy Water Sales Net of Costs**	4	N/A	[redacted]	[redacted]
6	**Deduct: Amortization of Return on Equity Components of Variance and Deferral Account Balances**	5	0.5	0.0	0.5
7	**Regulatory EBIT** (lines 1+2-3-4-5-6)		699.0	559.5	1,258.5
Deemed Cost of Capital:					
8	**Deduct: Cost of Deemed Debt for Regulated Assets**	6	162.1	183.8	345.9
9	**Deduct: Cost Related to UNL/ARC Adjustment**	6	N/A	18.3	18.3
10	**Add: Cost of Capital Variance and Deferral Account Additions**	7	3.2	15.8	19.0
11	**Regulatory EBT** (line 7 - line 8 - line 9 + line 10)		540.1	373.2	913.3
Determination of Regulatory Return on Equity:					
12	**Deduct: Regulatory Income Taxes on Regulated Assets**	8	106.3	28.4	134.7
13	**Regulatory Return on Equity** (line 11 - line 12)		433.8	344.8	778.6

See Table 2a for notes

Numbers may not add due to rounding.

Submitted: July 29, 2022

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 2a
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2021
Notes to Table 2

Notes:

1 Represents the actual regulatory return on equity for the year ended December 31, 2021, reflecting the completed 2021 tax return and updated cash working capital for both nuclear and regulated hydroelectric segments of the business for results from 2021.

2 Actual amounts on lines 1, 2, and 3 are determined in accordance with United States Generally Accepted Accounting Principles (US GAAP), as approved by the OEB for use by OPG for regulatory accounting, reporting and rate-making purposes. These amounts are determined using the same methodology as reflected in the 2019/2018 audited financial statements for OPG's prescribed facilities filed in EB-2020-0290 Ex. A2-1-1, Attachment 2.

3 During 2021, hydroelectric incentive mechanism (HIM) revenue was earned pursuant to the mechanism approved by the OEB in EB-2013-0321 and continued in EB-2016-0152.

[redacted]

[redacted]

4 Heavy water sales net of costs are applied by the OEB as a reduction to OPG's nuclear revenue requirement. In EB-2010-0008, the OEB approved a sharing mechanism for heavy water sales net of costs between OPG and ratepayers. The shareholder portion of heavy water sales net of costs represents the excess, if any, of the actual sales net of costs in 2021 reflected in the EB-2016-0152 Payment Amounts Order.

5 Amounts represent differences between the cost of capital additions recognized in the variance and deferral accounts, and the corresponding regulatory assets reflected in the US GAAP financial statements. In accordance with US GAAP, OPG limits the portion of cost of capital additions recognized as a regulatory asset in the financial statements to amounts calculated using the average rate of capitalized interest applied by OPG to construction and development in progress balances.

6 Costs related to deemed debt and UNL/ARC adjustment for 2021 are allocated to Regulated Hydroelectric and Nuclear based on actual rate base, using the same methodology applied in EB-2016-0152, as follows:

Table to Note 6 ($M)

Line No.	Item	Regulated Hydroelectric	Nuclear
		(a)	(b)
1a	Interest Rate (Table 1, line 4, col. (c))	3.92%	3.92%
2a	Actual Rate Base (Table 1, line 8, col. (a))	7,517.5	8,900.9
3a	ARC / UNL Adjustment (Table 1, line 7, col. (a))	N/A	376.2
4a	Rate Base Financed by Capital Structure	7,517.5	8,524.8
	(line 2a - line 3a)		
5a	Debt Ratio (Table 1, line 4, col. (b))	55.0%	55.0%
6a	Deemed Debt (line 4a x line 5a)	4,134.6	4,688.6
7a	Cost of Deemed Debt for Regulated Assets	162.1	183.8
	(line 1a x line 6a)		
8a	Cost Related to UNL/ARC Adjustment	N/A	18.3
	(Table 1, line 7, col. (c) x line 3a)		

7 The amounts represent the cost of capital additions to the Capacity Refurbishment Variance Account, the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account, the Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2017) Deferral Account, and the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account recorded in 2021.

8 The amount of regulatory income taxes is determined based on Regulatory EBT at line 11, using the methodology for calculating regulatory income taxes applied in EB-2016-0152, as adjusted to reflect the inclusion of income tax amounts in certain deferral and variance accounts (i.e. the impact of tax additions and deductions that represent items for which the tax cost or benefit is being passed on to ratepayers through deferral and variance accounts) and to exclude the benefit of tax losses forecasted in EB-2016-0152 to be carried forward beyond the 2017-2021 period. The amount of regulatory income taxes reflects the 2021 income tax return completed in June 2022.

Numbers may not add due to rounding.

Submitted: July 31, 2023 Revised

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 1
Summary of Actual Capitalization and Cost of Capital
Year Ended December 31, 2022

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1, 2	0.0	0.0	0.79%	3.6
2	**Existing Long-term Debt**	1	3,556.5	21.9%	3.83%	136.3
3	**Other Long-term Debt Provision**	1, 3	5,375.9	33.1%	3.83%	206.0
4	**Total Debt**	4	8,932.4	55.0%	3.87%	345.8
5	**Common Equity**	4,5	7,308.3	45.0%	12.41%	907.0
6	**Rate Base Financed by Capital Structure**	4	16,240.8	96.9%	7.71%	1,252.9
7	**Adjustment for Lesser of UNL or ARC**	1	519.3	3.1%	4.83%	25.1
8	**Rate Base**	1	16,760.0	100.0%	7.62%	1,277.9

Notes:

1 Amounts in cols. (a) and (d) and the cost rates in col. (c) are determined using the same methodologies as applied in EB-2020-0290.

2 The cost of short-term debt includes interest at the cost rate shown in col. (c) plus an allocation of the actual credit facility cost.

3 Debt required to balance capital structure with actual rate base.

4 Capital structure as approved by the OEB in EB-2020-0290.

5 Actual regulatory return on equity in col. (d) from Table 2, line 13, col. (c).

Numbers may not add due to rounding.

Submitted: July 31, 2023 Revised

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 2
Actual Regulatory Return on Equity ($M)[1]
Year Ended December 31, 2022

Line No.	Description	Note	Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
1	**Accounting EBIT (includes rounding)**	1	688.8	752.2	1,441.0
Accounting Expenses/Revenues not Included in Regulatory EBIT:					
2	**Add: Accretion on Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities**	1	N/A	[redacted]	[redacted]
3	**Deduct: Earnings/(Losses) on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds**	1	N/A	[redacted]	[redacted]
Differences Between Accounting and Regulatory Treatment:					
4	**Deduct: Shareholder Portion of Hydroelectric Incentive Mechanism Revenue**	2	[redacted]	N/A	[redacted]
5	**Deduct: Shareholder Portion of Heavy Water Sales Net of Costs**	3	N/A	[redacted]	[redacted]
6	**Deduct: Amortization of Return on Equity Components of Variance and Deferral Account Balances**	4	0.4	1.7	2.1
7	**Regulatory EBIT** (lines 1+2-3-4-5-6)		688.4	759.2	1,447.6
Deemed Cost of Capital:					
8	**Deduct: Cost of Deemed Debt for Regulated Assets**	5	164.7	181.1	345.8
9	**Deduct: Cost Related to UNL/ARC Adjustment**	5	N/A	25.1	25.1
10	**Add: Cost of Capital Variance and Deferral Account Additions**	6	27.9	21.9	49.7
11	**Regulatory EBT** (line 7 - line 8 - line 9 + line 10)		551.6	574.9	1,126.4
Determination of Regulatory Return on Equity:					
12	**Deduct: Regulatory Income Taxes on Regulated Assets**	7	121.6	97.8	219.4
13	**Regulatory Return on Equity** (line 11 - line 12)		430.0	477.1	907.0

See Table 2a for notes

Numbers may not add due to rounding.

Submitted: July 31, 2023 Revised

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 2a
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2022
Notes to Table 2

Notes:

1 Actual amounts on lines 11, 12, and 13 are determined in accordance with United States Generally Accepted Accounting Principles (US GAAP), as approved by the OEB for use by OPG for regulatory accounting, reporting and rate-making purposes. These amounts are determined using the same methodology as reflected in the 2019/2018 audited financial statements for OPG's prescribed facilities filed in EB-2020-0290 Ex. A2-1-1, Attachment 2.

2 During 2022, hydroelectric incentive mechanism (HIM) revenue was earned pursuant to the mechanism approved by the OEB in EB-2013-0321, EB-2016-0152 and continued in EB-2020-0290.

[redacted]

3 Heavy water sales net of costs are applied by the OEB as a reduction to OPG's nuclear revenue requirement. In EB-2010-0008, the OEB approved a sharing mechanism for heavy water sales net of costs between OPG and ratepayers. The shareholder portion of heavy water sales net of costs represents the excess, if any, of the actual sales net of costs in 2022 reflected in the EB-2020-0290 Payment Amounts Order.

4 Amounts represent differences between the cost of capital additions recognized in the variance and deferral accounts, and the corresponding regulatory assets reflected in the US GAAP financial statements. In accordance with US GAAP, OPG limits the portion of cost of capital additions recognized as a regulatory asset in the financial statements to amounts calculated using the average rate of capitalized interest applied by OPG to construction and development in progress balances.

5 Costs related to deemed debt and UNL/ARC adjustment for 2022 are allocated to Regulated Hydroelectric and Nuclear based on actual rate base, using the same methodology applied in EB-2020-0290, as follows:

Table to Note 6 ($M)

Line No.	Item	Regulated Hydroelectric	Nuclear
		(a)	(b)
1a	Interest Rate (Table 1, line 4, col. (c))	3.87%	3.87%
2a	Actual Rate Base (Table 1, line 8, col. (a))	7,734.7	9,025.3
3a	ARC / UNL Adjustment (Table 1, line 7, col. (a))	N/A	519.3
4a	Rate Base Financed by Capital Structure	7,734.7	8,506.0
	(line 2a - line 3a)		
5a	Debt Ratio (Table 1, line 4, col. (b))	55.0%	55.0%
6a	Deemed Debt (line 4a x line 5a)	4,254.1	4,678.3
7a	Cost of Deemed Debt for Regulated Assets	164.7	181.1
	(line 1a x line 6a)		
8a	Cost Related to UNL/ARC Adjustment	N/A	25.1
	(Table 1, line 7, col. (c) x line 3a)		

6 The amounts represent the cost of capital additions to the Capacity Refurbishment Variance Account, the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account, the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account, and the Nuclear Liabilities Deferral Account recorded in 2022.

7 The amount of regulatory income taxes is determined based on Regulatory EBT at line 11, using the methodology for calculating regulatory income taxes applied in EB-2020-0290, as adjusted to reflect the inclusion of income tax amounts in certain deferral and variance accounts (i.e. the impact of tax additions and deductions that represent items for which the tax cost or benefit is being passed on to ratepayers through deferral and variance accounts) and to exclude the benefit of tax losses forecasted in EB-2020-0290 to be carried forward beyond the 2022-2026 period. The amount of regulatory income taxes reflects the 2022 income tax return completed in June 2023.

Numbers may not add due to rounding.

Submitted: July 31, 2024 Revised

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 1
Summary of Actual Capitalization and Cost of Capital
Year Ended December 31, 2023

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1, 2	11.90	0.1%	5.20%	4.2
2	**Existing Long-term Debt**	1	3,793.3	21.6%	3.77%	143.1
3	**Other Long-term Debt Provision**	1, 3	5,842.4	33.3%	3.77%	220.4
4	**Total Debt**	4	9,647.7	55.0%	3.81%	367.7
5	**Common Equity**	4,5	7,893.6	45.0%	13.71%	1,082.0
6	**Rate Base Financed by Capital Structure**	4	17,541.2	98.3%	8.26%	1,449.7
7	**Adjustment for Lesser of UNL or ARC**	1	300.2	1.7%	4.79%	14.4
8	**Rate Base**	1	17,841.4	100.0%	8.21%	1,464.1

Notes:
1 Amounts in cols. (a) and (d) and the cost rates in col. (c) are determined using the same methodologies as applied in EB-2020-0290.
2 The cost of short-term debt includes interest at the cost rate shown in col. (c) plus an allocation of the actual credit facility cost.
3 Debt required to balance capital structure with actual rate base.
4 Capital structure as approved by the OEB in EB-2020-0290.
5 Actual regulatory return on equity in col. (d) from Table 2, line 13, col. (c).

Numbers may not add due to rounding.

Submitted: July 31, 2024 Revised

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 2
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2023

Line No.	Description	Note	Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
1	**Accounting EBIT (includes rounding)**	1	585.7	990.5	1,576.2
Accounting Expenses/Revenues not Included in Regulatory EBIT:					
2	**Add: Accretion on Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities**	1	N/A	[redacted]	[redacted]
3	**Deduct: Earnings/(Losses) on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds**	1	N/A	[redacted]	[redacted]
Differences Between Accounting and Regulatory Treatment:					
4	**Deduct: Shareholder Portion of Hydroelectric Incentive Mechanism Revenue**	2	[redacted]	N/A	[redacted]
5	**Deduct: Shareholder Portion of Heavy Water Sales Net of Costs**	3	N/A	[redacted]	[redacted]
6	**Deduct: Amortization of Return on Equity Components of Variance and Deferral Account Balances**	4	0.4	1.7	2.1
7	**Regulatory EBIT** (lines 10+11-12-13-14-15)		585.3	1,003.3	1,588.6
Deemed Cost of Capital:					
8	**Deduct: Cost of Deemed Debt for Regulated Assets**	5	167.5	200.2	367.7
9	**Deduct: Cost Related to UNL/ARC Adjustment**	5	N/A	14.4	14.4
10	**Add: Cost of Capital Variance and Deferral Account Additions**	6	41.8	79.3	121.1
11	**Regulatory EBT** (line 16 - line 17 - line 18 + line 19)		459.6	867.9	1,327.6
Determination of Regulatory Return on Equity:					
12	**Deduct: Regulatory Income Taxes on Regulated Assets**	7	104.5	141.1	245.6
13	**Regulatory Return on Equity** (line 20 - line 21)		355.1	726.8	1,082.0

See Table 2a for notes

Numbers may not add due to rounding.

Submitted: July 31, 2024 Revised

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 2a
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2023
Notes to Table 2

Notes:

1 Actual amounts on lines 10, 11, and 12 are determined in accordance with US GAAP, as approved by the OEB for use by OPG for regulatory accounting, reporting and rate-making purposes. These amounts are determined using the same methodology as reflected in the 2019/2018 audited financial statements for OPG's prescribed facilities filed in EB-2020-0290 Ex. A2-1-1, Attachment 2.

2 During 2024, hydroelectric incentive mechanism (HIM) revenue was earned pursuant to the mechanism approved by the OEB in EB-2013-0321, EB-2016-0152 and continued in EB-2020-0290.

[redacted]

3 Heavy water sales net of costs are applied by the OEB as a reduction to OPG's nuclear revenue requirement. In EB-2010-0008, the OEB approved a sharing mechanism for heavy water sales net of costs between OPG and ratepayers. The shareholder portion of heavy water sales net of costs represents the excess, if any, of the actual sales net of costs in 2023 reflected in the EB-2020-0290 Payment Amounts Order.

4 Amounts represent differences between the cost of capital additions recognized in the variance and deferral accounts, and the corresponding regulatory assets reflected in the US GAAP financial statements. In accordance with US GAAP, OPG limits the portion of cost of capital additions recognized as a regulatory asset in the financial statements to amounts calculated using the average rate of capitalized interest applied by OPG to construction and development in progress balances.

5 Costs related to deemed debt and UNL/ARC adjustment for 2023 are allocated to Regulated Hydroelectric and Nuclear based on actual rate base, using the same methodology applied in EB-2020-0290, as follows:

Table to Note 5 ($M)

Line No.	Item	Regulated Hydroelectric	Nuclear
		(a)	(b)
1a	Interest Rate (Table 1, line 4, col. (c))	3.81%	3.81%
2a	Actual Rate Base (Table 1, line 8, col. (a))	7,990.0	9,851.4
3a	ARC / UNL Adjustment (Table 1, line 7, col. (a))	N/A	300.2
4a	Rate Base Financed by Capital Structure	7,990.0	9,551.2
	(line 2a - line 3a)		
5a	Debt Ratio (Table 1, line 4, col. (b))	55.0%	55.0%
6a	Deemed Debt (line 4a x line 5a)	4,394.5	5,253.2
7a	Cost of Deemed Debt for Regulated Assets	167.5	200.2
	(line 1a x line 6a)		
8a	Cost Related to UNL/ARC Adjustment	N/A	14.4
	(Table 1, line 7, col. (c) x line 3a)		

6 The amounts represent the cost of capital additions to the Capacity Refurbishment Variance Account, the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account, the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account, and the Nuclear Liabilities Deferral Account recorded in 2023.

7 The amount of regulatory income taxes is determined based on Regulatory EBT at line 11, using the methodology for calculating regulatory income taxes applied in EB-2020-0290, as adjusted to reflect the inclusion of income tax amounts in certain deferral and variance accounts (i.e. the impact of tax additions and deductions that represent items for which the tax cost or benefit is being passed on to ratepayers through deferral and variance accounts) and to exclude the benefit of tax losses forecasted in EB-2020-0290 to be carried forward beyond the 2022-2026 period. The amount of regulatory income taxes reflects the 2023 income tax return completed in June 2024 and a true-up to incorporate changes from an amendment filed in 2023 to the 2022 income tax return.

Numbers may not add due to rounding.

Submitted: July 31, 2025 Revised

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 1
Summary of Actual Capitalization and Cost of Capital
Year Ended December 31, 2024

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1, 2	124.5	0.6%	4.79%	9.4
2	**Existing Long-term Debt**	1	4,306.1	22.5%	3.92%	168.9
3	**Other Long-term Debt Provision**	1, 3	6,109.3	31.9%	3.92%	239.6
4	**Total Debt**	4	10,539.9	55.0%	3.97%	417.9
5	**Common Equity**	4,5	8,623.5	45.0%	5.86%	505.1
6	**Rate Base Financed by Capital Structure**	4	19,163.4	97.0%	4.82%	923.0
7	**Adjustment for Lesser of UNL or ARC**	1	591.4	3.0%	4.72%	27.9
8	**Rate Base**	1	19,754.8	100.0%	4.81%	951.0

Notes:

1 Amounts in cols. (a) and (d) and the cost rates in col. (c) are determined using the same methodologies as applied in EB-2020-0290.

2 The cost of short-term debt includes interest at the cost rate shown in col. (c) plus an allocation of the actual credit facility cost.

3 Debt required to balance capital structure with actual rate base.

4 Capital structure as approved by the OEB in EB-2020-0290.

5 Actual regulatory return on equity in col. (d) from Table 2, line 13, col. (c).

Numbers may not add due to rounding.

Submitted: July 31, 2025 Revised

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 2
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2024

Line No.	Description	Note	Regulated Hydroelectric	Nuclear	Total
			(a)	(b)	(c)
1	**Accounting EBIT (includes rounding)**	1	597.2	267.3	864.5
Accounting Expenses/Revenues not Included in Regulatory EBIT:					
2	**Add: Accretion on Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities**	1	N/A	[redacted]	[redacted]
3	**Deduct: Earnings/(Losses) on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds**	1	N/A	[redacted]	[redacted]
Differences Between Accounting and Regulatory Treatment:					
4	**Deduct: Shareholder Portion of Hydroelectric Incentive Mechanism Revenue**	2	[redacted]	N/A	[redacted]
5	**Deduct: Shareholder Portion of Heavy Water Sales Net of Costs**	3	N/A	[redacted]	[redacted]
6	**Deduct: Amortization of Return on Equity Components of Variance and Deferral Account Balances**	4	3.6	8.4	12.0
7	**Regulatory EBIT** (lines 1+2-3-4-5-6)		593.6	265.2	858.8
Deemed Cost of Capital:					
8	**Deduct: Cost of Deemed Debt for Regulated Assets**	5	177.2	240.8	417.9
9	**Deduct: Cost Related to UNL/ARC Adjustment**	5	N/A	27.9	27.9
10	**Add: Cost of Capital Variance and Deferral Account Additions**	6	49.4	28.5	78.0
11	**Regulatory EBT** (line 7 - line 8 - line 9 + line 10)		465.8	25.1	490.9
Determination of Regulatory Return on Equity:					
12	**Deduct: Regulatory Income Taxes on Regulated Assets**	7	6.7	(20.9)	(14.2)
13	**Regulatory Return on Equity** (line 11 - line 12)		459.1	46.0	505.1

See Table 2a for notes

Numbers may not add due to rounding.

Submitted: July 31, 2025 Revised

Ontario Power Generation Inc.
Reporting and Record Keeping Requirements

Table 2a
Actual Regulatory Return on Equity ($M)
Year Ended December 31, 2024
Notes to Table 2

Notes:

1 Actual amounts on lines 1, 2, and 3 are determined in accordance with US GAAP, as approved by the OEB for use by OPG for regulatory accounting, reporting and rate-making purposes. These amounts are determined using the same methodology as reflected in the 2019/2018 audited financial statements for OPG's prescribed facilities filed in EB-2020-0290 Ex. A2-1-1, Attachment 2.

2 During 2024, hydroelectric incentive mechanism (HIM) revenue was earned pursuant to the mechanism approved by the OEB in EB-2013-0321, EB-2016-0152 and continued in EB-2020-0290.

[redacted]

3 Heavy water sales net of costs are applied by the OEB as a reduction to OPG's nuclear revenue requirement. In EB-2010-0008, the OEB approved a sharing mechanism for heavy water sales net of costs between OPG and ratepayers. The shareholder portion of heavy water sales net of costs represents the excess, if any, of the actual sales net of costs in 2024 reflected in the EB-2020-0290 Payment Amounts Order.

4 Amounts represent differences between the cost of capital additions recognized in the variance and deferral accounts, and the corresponding regulatory assets reflected in the US GAAP financial statements. In accordance with US GAAP, OPG limits the portion of cost of capital additions recognized as a regulatory asset in the financial statements to amounts calculated using the average rate of capitalized interest applied by OPG to construction and development in progress balances.

5 Costs related to deemed debt and UNL/ARC adjustment for 2024 are allocated to Regulated Hydroelectric and Nuclear based on actual rate base, using the same methodology applied in EB-2020-0290, as follows:

Table to Note 5 ($M)

Line No.	Item	Regulated Hydroelectric	Nuclear
		(a)	(b)
1a	Interest Rate (Table 1, line 4, col. (c))	3.97%	3.97%
2a	Actual Rate Base (Table 1, line 8, col. (a))	8,124.4	11,630.4
3a	ARC / UNL Adjustment (Table 1, line 7, col. (a))	N/A	591.4
4a	Rate Base Financed by Capital Structure	8,124.4	11,039.0
	(line 2a - line 3a)		
5a	Debt Ratio (Table 1, line 4, col. (b))	55.0%	55.0%
6a	Deemed Debt (line 4a x line 5a)	4,468.4	6,071.5
7a	Cost of Deemed Debt for Regulated Assets	177.2	240.8
	(line 1a x line 6a)		
8a	Cost Related to UNL/ARC Adjustment	N/A	27.9
	(Table 1, line 7, col. (c) x line 3a)		

6 The amounts represent the cost of capital additions to the Capacity Refurbishment Variance Account, the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account, the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account, and the Nuclear Liability Deferral Account recorded in 2024.

7 The amount of regulatory income taxes is determined based on Regulatory EBT at line 11, using the methodology for calculating regulatory income taxes applied in EB-2020-0290, as adjusted to reflect the inclusion of income tax amounts in certain deferral and variance accounts (i.e. the impact of tax additions and deductions that represent items for which the tax cost or benefit is being passed on to ratepayers through deferral and variance accounts) and to exclude the benefit of tax losses forecasted in EB-2020-0290 to be carried forward beyond the 2022-2026 period. The amount of regulatory income taxes reflects the 2024 income tax return completed in June 2025.

SEC Interrogatory #034

Interrogatory

Reference:
C1-1-1, Tables 1-5

Question(s):

Please provide revised versions of Tables 1-5 that show the cost of capital with the existing 45% equity ratio, and a variance analysis showing the difference as compared to the proposed equity ratio.

Response

The requested cost of capital tables are provided as Attachment 1. A comparison of the cost of capital amounts in the revised tables against the proposed cost of capital amounts is provided in Chart 1, below.

Chart 1
OPG Cost of Capital: Proposed vs. Hypothetical Scenario

	2027	2028	2029	2030	2031
Cost of Debt ($M)[1]	547.7	596.6	636.8	674.2	850.6
Hypothetical Cost of Debt ($M)[2]	627.3	683.6	729.7	772.7	974.8
Difference	79.6	87.0	92.9	98.5	124.2
Cost of Equity ($M)[3]	1,172.9	1,228.5	1,280.3	1,340.2	1,684.2
Hypothetical Cost of Equity ($M)[2]	1,014.5	1,062.7	1,107.6	1,159.5	1,457.2
Difference	(158.4)	(165.8)	(172.7)	(180.7)	(227.0)

Notes
[1] Ex. C1-1-1, Tables 1-5: line 4.
[2] Recalculated using 45% equity, 55% debt.
[3] Ex. C1-1-1, Tables 1-5: line 5b.

Numbers may not add due to rounding.

Filed: 2026-04-22
EB-2025-0297
Exhibit L
C1-SEC-034
Attachment 1

Table 1
Hypothetical Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital - OPG
Calendar Year Ending December 31, 2031

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	414.3	1.2%	3.39%	19.9
2	**Existing/Planned Long-Term Debt**	2	13,503.3	37.9%	4.98%	672.8
3	**Other Long-Term Debt Provision**	3	5,659.8	15.9%	4.98%	282.0
4	**Total Debt**	4	19,577.4	55.0%	4.98%	974.8
5	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	7	49.6	0.1%	4.98%	2.5
5a	**Common Equity**	4	15,968.3	44.9%	9.11%	1,454.7
5b	**Total Equity**		16,017.9	45.0%	9.10%	1,457.2
6	**Rate Base Financed by Capital Structure**	5	35,595.3	100.0%	6.83%	2,432.0
7	**Adjustment for Lesser of UNL or ARC**	5, 6	0.0	0.0%	4.72%	0.0
8	**Rate Base**		35,595.3	100.0%	6.83%	2,432.0

Notes:

1 Ex. C1-1-3, Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. C1-1-2 Table 13, line 43.

3 Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.

4 Hypothetical capital structure per Ex. L-C1-SEC-034.

5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from Ex. C2-1-1 Table 2, line 28. Cost rate from Ex. C2-1-1, Table 1b, line 14, col (d).

7 Represents the portion of rate base financed by common equity that is subject to return at the long-term debt rate until the end of 2036 per the EB-2020-0290 settlement proposal approved by the OEB (EB-2020-0290 Decision and Order, Schedule A, P. 23).

Table 2
Hypothetical Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital - OPG
Calendar Year Ending December 31, 2030

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	414.3	1.5%	3.22%	19.2
2	**Existing/Planned Long-Term Debt**	2	12,948.0	45.7%	4.97%	643.1
3	**Other Long-Term Debt Provision**	3	2,223.9	7.8%	4.97%	110.5
4	**Total Debt**	4	15,586.3	55.0%	4.96%	772.7
5	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	7	53.9	0.2%	4.97%	2.7
5a	**Common Equity**	4	12,698.5	44.8%	9.11%	1156.8
5b	**Total Equity**		12,752.4	45.0%	9.09%	1,159.5
6	**Rate Base Financed by Capital Structure**	5	28,338.6	100.0%	6.82%	1,932.3
7	**Adjustment for Lesser of UNL or ARC**	5, 6	0.0	0.0%	4.72%	0.0
8	**Rate Base**		28,338.6	100.0%	6.82%	1,932.3

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. C1-1-2 Table 12, line 43.

3 Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.

4 Hypothetical capital structure per Ex. L-C1-SEC-034.

5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from Ex. C2-1-1 Table 2, line 28. Cost rate from Ex. C2-1-1, Table 1b, line 14, col (d).

7 Represents the portion of rate base financed by common equity that is subject to return at the long-term debt rate until the end of 2036 per the EB-2020-0290 settlement proposal approved by the OEB (EB-2020-0290 Decision and Order, Schedule A, P. 23).

Table 3
Hypothetical Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital - OPG
Calendar Year Ending December 31, 2029

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	414.3	1.5%	3.07%	20.1
2	**Existing/Planned Long-Term Debt**	2	10,958.5	40.5%	4.90%	537.1
3	**Other Long-Term Debt Provision**	3	3,520.6	13.0%	4.90%	172.6
4	**Total Debt**	4	14,893.5	55.0%	4.90%	729.7
5	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	7	59.6	0.2%	4.90%	2.9
5a	**Common Equity**	4	12,126.0	44.8%	9.11%	1,104.7
5b	**Total Equity**		12,185.6	45.0%	9.09%	1,107.6
6	**Rate Base Financed by Capital Structure**	5	27,079.0	100.0%	6.78%	1,837.3
7	**Adjustment for Lesser of UNL or ARC**	5, 6	0.0	0.0%	4.72%	0.0
8	**Rate Base**		27,079.0	100.0%	6.78%	1,837.3

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. C1-1-2 Table 11, line 41.

3 Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.

4 Hypothetical capital structure per Ex. L-C1-SEC-034.

5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from Ex. C2-1-1 Table 2, line 28. Cost rate from Ex. C2-1-1, Table 1b, line 14, col (d).

7 Represents the portion of rate base financed by common equity that is subject to return at the long-term debt rate until the end of 2036 per the EB-2020-0290 settlement proposal approved by the OEB (EB-2020-0290 Decision and Order, Schedule A, P. 23).

Table 4
Hypothetical Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital - OPG
Calendar Year Ending December 31, 2028

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	414.3	1.6%	2.93%	19.5
2	**Existing/Planned Long-Term Debt**	2	8,335.3	32.1%	4.78%	398.8
3	**Other Long-Term Debt Provision**	3	5,546.2	21.3%	4.78%	265.4
4	**Total Debt**	4	14,295.8	55.0%	4.78%	683.6
5	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	7	66.1	0.3%	4.78%	3.2
5a	**Common Equity**	4	11,630.5	44.7%	9.11%	1,059.5
5b	**Total Equity**		11,696.6	45.0%	9.09%	1,062.7
6	**Rate Base Financed by Capital Structure**	5	25,992.3	99.9%	6.72%	1,746.3
7	**Adjustment for Lesser of UNL or ARC**	5, 6	23.0	0.1%	4.72%	1.1
8	**Rate Base**		26,015.4	100.0%	6.72%	1,747.4

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. C1-1-2 Table 10, line 35.

3 Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.

4 Hypothetical capital structure per Ex. L-C1-SEC-034.

5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from Ex. C2-1-1 Table 2, line 28. Cost rate from Ex. C2-1-1, Table 1b, line 14, col (d).

7 Represents the portion of rate base financed by common equity that is subject to return at the long-term debt rate until the end of 2036 per the EB-2020-0290 settlement proposal approved by the OEB (EB-2020-0290 Decision and Order, Schedule A, P. 23).

Numbers may not add due to rounding.

Table 5
Hypothetical Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital - OPG
Calendar Year Ending December 31, 2027

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	414.3	1.7%	2.79%	21.0
2	**Existing/Planned Long-Term Debt**	2	6,475.7	26.1%	4.58%	296.5
3	**Other Long-Term Debt Provision**	3	6,766.4	27.3%	4.58%	309.8
4	**Total Debt**	4	13,656.4	55.0%	4.59%	627.3
5	**EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate**	7	73.9	0.3%	4.58%	3.4
5a	**Common Equity**	4	11,099.5	44.7%	9.11%	1,011.2
5b	**Total Equity**		11,173.4	45.0%	9.08%	1,014.5
6	**Rate Base Financed by Capital Structure**	5	24,829.8	99.6%	6.61%	1,641.8
7	**Adjustment for Lesser of UNL or ARC**	5, 6	100.1	0.4%	4.72%	4.7
8	**Rate Base**		24,929.8	100.0%	6.60%	1,646.5

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 7), Cost Rate (line 2), Cost of Capital (line 8). Cost includes interest at the cost rate shown plus an allocation of the credit facility cost.

2 Ex. C1-1-2 Table 9, line 31.

3 Debt required to balance capital structure with proposed rate base. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2). See Ex. C1-1-2, Section 5.0.

4 Hypothetical capital structure per Ex. L-C1-SEC-034.

5 The portion of rate base to be financed by the capital structure approved by the OEB excludes the lesser of the forecast of the average unfunded nuclear liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from Ex. C2-1-1 Table 2, line 28. Cost rate from Ex. C2-1-1, Table 1b, line 14, col (d).

7 Represents the portion of rate base financed by common equity that is subject to return at the long-term debt rate until the end of 2036 per the EB-2020-0290 settlement proposal approved by the OEB (EB-2020-0290 Decision and Order, Schedule A, p. 23).

SEC Interrogatory #035

Interrogatory

Reference:
C1-1-1, Attachment 1, p. 47

Question(s):

Please provide a copy of any analysis OPG undertook in the development, consultation or consideration, or after, of the amendments to O.Reg. 53/05 regarding the impact of concurrent cost recovery on OPG's financial metrics.

Response

OPG did not conduct an analysis of the type referenced in question after the amendments to O. Reg 53/05 establishing the concurrent cost recovery ("CCR") mechanisms for the Pickering Refurbishment Program and the Darlington New Nuclear Program came into effect. However, an estimate of the impact of such mechanisms on OPG's credit metrics as presented in OPG's 2025-2031 Business Plan (Ex. A2-2-1, Attachment 1, p. 10) is provided in Attachment 1 (Confidential). As the amendments are now in effect and must be adhered to in this proceeding, any analysis conducted prior to the amendments is not relevant to this process.

Exhibit L-C1-SEC-035, Attachment 1

OPG Modelled Financial Metrics - With and Without CCR

This Attachment was filed as confidential information in its entirety.

SEC Interrogatory #036

Interrogatory

Reference:
C1-1-1, Attachment 3, p. 34

Question(s):

With respect to the *Initial Financing For Darlington New Nuclear Program* Report, Evidence by Cliff Inskip, is the key reason that Mr. Inskip believes "that there is a low or very low probability of a successful offering of investment grade non-recourse bonds within 12-18 months following the in-service date of the first SMR unit for the DNNP" because there will be units whose construction is in progress? Put another way, if there was only a single SMR unit to be constructed, would Mr. Inskip have come to a different conclusion.

Response

This response was prepared by Polar Star Advisory Services ("Polar Star")

No, the key reason for my conclusion stated above is not because there will be units whose construction is in progress. I would also not come to a different conclusion if there was only a single SMR to be constructed rather than four SMRs. The key reason for my conclusion is the FOAK nuclear technology risk.

It should be noted, however, that changing a key assumption (such as the expected number of SMRs) cannot be evaluated in isolation without considering the overall risk analysis. While the number of SMRs being built would change the magnitude of individual risks, my conclusion (that there is a low to very low probability of a successful offering of investment grade non-recourse bonds within 12-18 months following the in-service date of the first SMR unit for the DNNP) would not change if only a single unit was constructed rather than four units.

SEC Interrogatory #037

Interrogatory

Reference:
C1-1-1, Attachment 3, p. 39

Question(s):

With respect to the *Initial Financing For Darlington New Nuclear Program* Report, Evidence by Cliff Inskip, please provide copies of the material relied upon if not otherwise provided for in the evidence for items f, g, h, k, l, m, n, o, p and q.

Response

Evidence for items f, g, h, k, l, m, n, o, p are provided in Attachment 1.

Evidence for item q, is provided in Attachment 2 (Confidential).

MORNINGSTAR | DBRS

Commentary

Ontario's Nuclear Outlook Brightens: Proposed Regulatory Amendments Seen as Credit Positive for SMRs and Refurbishments

Morningstar DBRS
June 3, 2025

Key Highlights

- Ontario launched North America's first commercial, grid-scale SMR construction to secure long-term energy system reliability and build leadership in emerging nuclear technologies.
- The proposed regulatory framework considers a CCR mechanism, and enables equity participation from Indigenous communities and public and private parties.
- OPG's financial resilience during the construction period could be meaningfully enhanced, assuming successful implementation of the CCR regulatory framework and effective execution of SMR development schedule.

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Overview

On May 8, 2025, the Province of Ontario (Ontario or the Province, rated AA with Stable trend) approved Ontario Power Generation Inc.'s (OPG or the Company, rated A (low) with Stable trend) plan to begin construction on North America's first commercial, grid-scale small modular reactor (SMR) at the Darlington New Nuclear Project (DNNP) site. The first unit, a 300 megawatts (MW) BWRX-300 reactor is expected to be in service by 2030. OPG, the owner and operator of the Darlington and Pickering nuclear power plants, is leading the development of DNNP. In total, OPG plans to construct four SMRs at the Darlington site with an installed capacity of approximately 1,200 MW, and a projected total investment of approximately $21 billion. OPG is also considering refurbishing (subject to final regulatory and provincial approvals) the four operating reactors at the Pickering Nuclear Generation Station (Pickering Refurbishment).

DNNP, and the Pickering Refurbishment (if approved), will result in OPG incurring significant capital expenditures over the medium term. Under the current Ontario Energy Board (OEB) regulatory framework, OPG can only begin to recover costs through OEB-approved rates once generation projects are complete and generating electricity. Given that the projected in-service date for the first unit at DNNP is 2030, OPG will have to bear the cost of debt for at least five years before it can start to recover these costs from ratepayers.

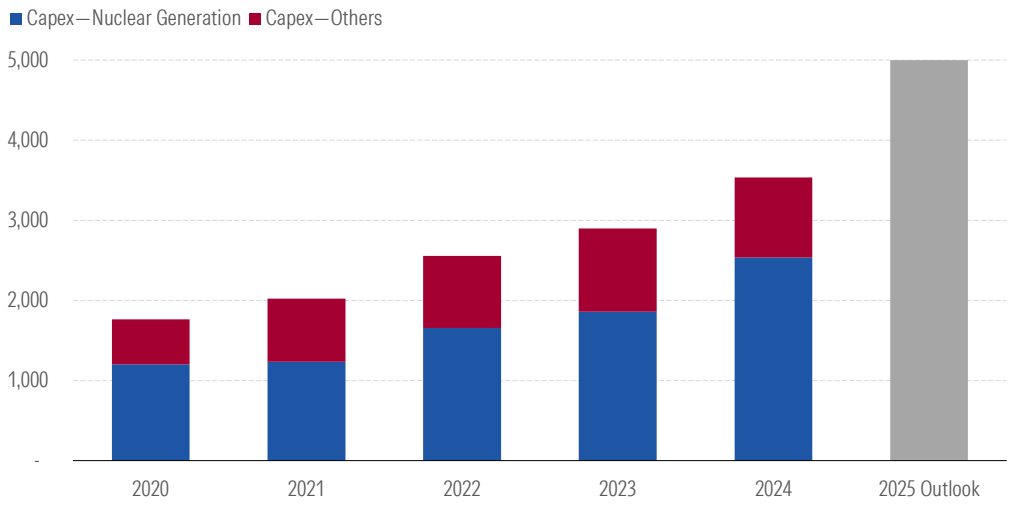
The Province is now proposing regulatory amendments to allow OPG to recover a debt rate return on the construction work in progress (CWIP) balance through the construction phase of DNNP and Pickering Refurbishment (if approved) as well as enabling OPG to establish commercial partnerships and obtain equity investments for DNNP. We believe that the proposed amendments are credit positive and will support OPG's credit metrics through the construction phase of DNNP and the Pickering Refurbishment.

Concurrent Cost Recovery Mechanism to Complement the Cost-of-Service Framework

To support the financing required for these large-scale projects, the Province is considering potential amendments to the OEB Act, 1998. The proposal is to establish a concurrent cost recovery (CCR) mechanism to allow OPG to recover interest costs on debt incurred during the construction phase for DNNP and the Pickering Refurbishment Project. While the cost-of-service (COS) model continuously serves as the primary regulatory framework, the proposal introduces the CCR mechanism as a complementary tool.

Under COS, utilities can only begin to recover capital and financing costs through rates once assets are placed in service. CCR, by contrast, would allow OPG to recover a debt rate return on CWIP balance at the DNNP and Pickering Refurbishment Project during the construction phase. This adjustment primarily changes the timing of cost recovery, aligning part of the revenue stream with capital outlays.

Exhibit 1 OPG's Capital Expenditure ($million)



Source: OPG's annual reports.
Note: Capex—Others includes regulated nuclear sustainability services, regulated hydro generation, and unregulated hydro generation, Atura Power, and others.

Large nuclear projects, especially those involving new technologies like SMRs, have long build timeframes and are capital intensive. These features introduce elevated execution and cost risks. Potential challenges, such as construction delays, supply chain disruptions, cost overruns, and evolving technical hurdles, remain material concerns. Any deviation from baseline assumptions could pressure OPG's financial metrics by increasing incremental financing loads and limiting financial flexibility or necessitate further public support. Without mechanisms to align cost recovery like CCR, such projects could result in delayed revenue recognition and negatively impact key credit metrics.

We treat the CCR framework as credit positive for OPG's credit rating. The CCR has a positive impact on the regulated utility's operating cash flow during the construction period, thereby reducing the need for more debt. As an illustrative example, assuming a regulated utility with a deemed debt rate of 5.0% and average balance of CWIP of $4 billion during the five-year construction period, it would recover approximately $1 billion during the construction phase, thereby reducing borrowings by a similar amount. As evident from this example, the larger the capital program, the greater the benefit to the regulated utility.

Provision for Equity Partnerships

The proposed framework also has an equity participation component for DNNP, including encouraging participation by Indigenous communities. Under the current framework, OPG is dependent on the

Province for equity injections if required. The proposed regulatory amendments broaden funding sources and encourages economic inclusion while maintaining the regulatory framework for setting rates. Nevertheless, the credit quality of the equity partners and terms of the equity investment will have an impact on our assessment of the credit impact of the equity investment.

Related Research

Ontario Power Generation Inc.: Credit Rating Report, April 21, 2025

Note: All figures are in Canadian dollars unless otherwise noted.

About Morningstar DBRS

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PRESS RELEASE

APRIL 11, 2025

Morningstar DBRS Confirms Ontario Power Generation Inc. at A (low)/R-1 (low) With Stable Trends

UTILITIES & INDEPENDENT POWER

DBRS Limited (Morningstar DBRS) confirmed Ontario Power Generation Inc.'s (OPG or the Company) Issuer Rating and Unsecured Debt credit rating at A (low) and its Commercial Paper credit rating at R-1 (low). All trends are Stable.

KEY CREDIT RATING CONSIDERATIONS

Morningstar DBRS' credit ratings on OPG are based on the Company's regulated generation business, which operates under a reasonable regulatory regime under the Ontario Energy Board. The Stable trends reflect the Company's key credit metrics, which remain reasonable despite the complex and substantial capital expenditures (capex) program.

Morningstar DBRS notes that OPG has a number of large capital projects ongoing. The Darlington Refurbishment Project, with total capex of $12.8 billion, is on track and on schedule. The start of Unit 4 marks the last of the four units being refurbished in Darlington, Ontario, and is scheduled to be returned to service in 2026. The Pickering Refurbishment Project, which aims to refurbish Units 5-8 of the Pickering Nuclear Generating Station (GS), is anticipated to return the units to service by the mid-2030s. In January 2025, the Province of Ontario (the Province; 100% owner of OPG; rated AA with a Stable trend by Morningstar DBRS) approved OPG's plan to proceed with the project definition phase as the next step toward the refurbishment. OPG expects Darlington's Small Modular Reactor (SMR) Unit 1 to begin commercial operation by the end of 2030. OPG is also planning for three additional SMRs at the Darlington site. On April 4, 2025, the Canadian Nuclear Safety Commission granted OPG a licence to construct one SMR. Additionally, the wholly owned subsidiary Atura Power, as part of OPG's nonregulated segment, is constructing several growth capex projects. With the electrification of the economy and the expected increase in electricity demand in the Province, the Company also intends to pursue opportunities to increase generation capacity such as through the Independent Electricity System Operator request for proposals or the development of hydro sites throughout the Province.

CREDIT RATING DRIVERS

Morningstar DBRS believes a positive credit rating action is unlikely over the medium term because of the Company's business profile and the ongoing significant and complex capex program. Morningstar DBRS could take a negative credit rating action if there were cost overruns resulting in significant stranded costs and lack of support from the Province.

EARNINGS OUTLOOK

OPG expects earnings in 2025 to be higher than in 2024, reflecting the positive impact of a full year of the Darlington GS Unit 1 returning to service and no other major outages planned at Darlington. Overall, Morningstar DBRS expects future earnings volatility to come from (1) forecast risk as part of the regulatory process; (2) macro factors such as weather, unexpected outages, and the Province's economic conditions; and (3) variability in water flows and wholesale electricity prices for uncontracted facilities.

FINANCIAL OUTLOOK

Given these ongoing projects, OPG has forecast capex to increase to approximately $5 billion in 2025 from $3.5 billion in 2024. Morningstar DBRS expects capex to remain at this level for at least the near term, which will likely result in substantial net free cash

flow deficits that will require debt financing. Morningstar DBRS notes that the Company is exploring additional credit supportive funding sources, which would reduce its debt needs. While most of OPG's projects are regulated and will be added to the Company's rate base when completed, there is significant execution risk because of the complexity and scale of the projects. Morningstar DBRS has factored into OPG's current credit ratings that its key credit metrics will weaken moderately over the medium term, and expects the key credit metrics to remain reasonable for the A (low) credit rating. Morningstar DBRS will continue to monitor progress on the Darlington Refurbishment, the Pickering Refurbishment, and the SMR project and expects that the Company will not undertake any major capex without having financing and a cost-recovery mechanism in place to minimize the financial risks.

CREDIT RATING RATIONALE

OPG's credit ratings are supported by the reasonable regulatory framework that provides stable cash flow, support from the Province, and limited nuclear waste management liabilities. This is offset by nuclear generation risk, risk of political intervention, the significant capex program, and a high cost base that has historically resulted in reductions in allowable costs through regulated rate setting.

ENVIRONMENTAL, SOCIAL, AND GOVERNANCE CONSIDERATIONS

There were no Environmental/Social/Governance factors that had a significant or relevant effect on the credit analysis.

A description of how Morningstar DBRS considers ESG factors within the Morningstar DBRS analytical framework can be found in the Morningstar DBRS Criteria: Approach to Environmental, Social, and Governance Factors in Credit Ratings at (August 13, 2024) https://dbrs.morningstar.com/research/437781.

BUSINESS RISK ASSESSMENT (BRA) AND FINANCIAL RISK ASSESSMENT (FRA)

(A) Weighting of BRA Factors

In the analysis of OPG, the BRA factors were considered in the order of importance contemplated in the methodology.

(B) Weighting of FRA Factors

In the analysis of OPG, the FRA factors were considered in the order of importance contemplated in the methodology.

(C) Weighting of the BRA and the FRA

In the analysis of OPG, the BRA carries greater weight than the FRA.

Notes:

All figures are in Canadian dollars unless otherwise noted.

Morningstar DBRS applied the following principal methodology:

-- Global Methodology for Rating Companies in the Regulated Utility and Independent Power Producer Industries (November 25, 2024), https://dbrs.morningstar.com/research/443429

Morningstar DBRS credit ratings may use of one or more sections of the Morningstar DBRS Global Corporate Criteria (February 3, 2025; https://dbrs.morningstar.com/research/447186), which covers, for example, topics such as holding companies and parent/subsidiary relationships, guarantees, recovery, and common adjustments to financial ratios.

The credit rating methodologies used in the analysis of this transaction can be found at: https://dbrs.morningstar.com/about/methodologies.

A description of how Morningstar DBRS analyzes corporate finance transactions and how the methodologies are collectively applied can be found at: https://dbrs.morningstar.com/research/431153

The related regulatory disclosures pursuant to the National Instrument 25-101 Designated Rating Organizations are hereby incorporated by reference and can be found by clicking on the link under Related Documents or by contacting us at info-DBRS@morningstar.com.

The credit ratings were initiated at the request of the rated entity.

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Ratings

Ontario Power Generation Inc.

Date Issued	Debt Rated	Action	Rating	Trend	Attributes
11-Apr-25	Issuer Rating	Confirmed	A (low)	Stb	CA
11-Apr-25	Unsecured Debt	Confirmed	A (low)	Stb	CA
11-Apr-25	Commercial Paper	Confirmed	R-1 (low)	Stb	CA

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Credit Rating Report
Ontario Power Generation Inc.

Morningstar DBRS
April 21, 2025

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Commercial Paper Limit
CAD 1.0 billion and USD 750 million

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Credit Ratings

Obligation	Credit Rating	Credit Rating Action	Trend
Issuer Rating	A (low)	Confirmed	Stable
Unsecured Debt	A (low)	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Credit Ratings Drivers

Positive Credit Rating Drivers	Negative Credit Rating Drivers
We believe a positive credit rating action is unlikely over the medium term given the business profile and the ongoing significant and complex capital expenditures (capex) program.	We could take a negative credit rating action should there be cost overruns that result in significant stranded costs and lack of support from the Province of Ontario.

Key Credit Rating Considerations

We based our credit ratings on Ontario Power Generation Inc. (OPG or the Company) on its regulated generation business, which operates under a reasonable regulatory regime under the Ontario Energy Board (OEB). The Stable trends reflect the Company's key credit metrics, which remain reasonable despite the complex and substantial capex program.

We note that OPG has a number of large capital projects ongoing. The Darlington Refurbishment Project, with total capex of $12.8 billion, is on track and on schedule. The refurbished Unit 3 and Unit 1 were reconnected to the electricity grid ahead of schedule in 2023 and 2024, respectively. Unit 4 is currently executing reassembly. The start of Unit 4 marks the last of the four units being refurbished in Darlington, Ontario, and is scheduled to be returned to service in 2026. The Pickering Refurbishment Project, which aims to refurbish Units 5-8 of the Pickering Nuclear Generating Station (GS), is anticipated to return the units to service by the mid-2030s. In January 2025, the Province of Ontario (the Province or Ontario; 100% owner of OPG; rated AA with a Stable trend) approved OPG's plan to proceed with the project definition phase as the next step toward the refurbishment. OPG's approved budget for this work is $4.1 billion, bring the total board-approved budget for the project to date to $6.2 billion.

Darlington's Small Modular Reactor (SMR) Unit 1 is expected to begin commercial operation by the end of 2030. OPG is also planning for three additional SMRs at the Darlington site. On April 4, 2025, the Canadian Nuclear Safety Commission (CNSC) granted OPG a licence to construct one SMR. Issuance of the licence to construct is a key milestone for the SMR project as it shows continued confidence from the Canadian nuclear regulator in OPG executing the SMR project.

Additionally, the wholly owned subsidiary Atura Power, as part of OPG's nonregulated segment, is constructing three projects, namely Niagara Hydrogen Center, Napanee battery energy storage system (BESS), and Napanee GS expansion, with a total capital budget of $1.5 billion. With the electrification of the economy and the expected increase in electricity demand in the Province, the Company also intends to pursue opportunities to increase generation capacity such as through Independent Electricity System Operator (IESO) request for proposals or the development of hydro sites throughout the Province.

Financial Outlook

Given these ongoing projects, in 2024 the Company reported a total capex of $3.5 billion, representing an increase of 22% compared with 2023. Over the 2025–26 period, OPG plans to invest approximately $12.7 billion in its generating fleet and other growth initiatives and subsidiaries. Capex remaining at this level in the near term will likely result in substantial net free cash flow deficits that will require debt financing. The Company is currently exploring additional credit supportive funding sources funding sources, which would reduce its debt needs. While most of OPG's projects are regulated and will be added to the Company's rate base when completed, there is significant execution risk because of the complexity and scale of the projects.

We have factored into OPG's current credit ratings that its key credit metrics will weaken moderately over the medium term, but, given the complexity of the projects, the key credit metrics remain reasonable for the A (low) credit rating. We will continue to monitor progress on the Darlington and Pickering refurbishment projects, the SMR project, and Federal and Provincial funding programs, and we expect that the Company will not undertake any major capex without having financing and a cost-recovery mechanism in place to minimize financial risks.

Earnings Outlook

OPG's net income for 2024 was $988 million, a decrease of 43% compared with 2023 because of (1) higher planned outage days on Unit 2 at the Darlington GS; (2) a planned shutdown of Unit 1 of the Pickering GS during 2024 resulting in lower nuclear production and higher operations, maintenance, and administrative costs; and (3) lower regulated nuclear prices being in effect for 2024. OPG expects earnings in 2025 to be higher than in 2024, reflecting the positive impact of a full year of the Darlington GS Unit 1 returning to service and no other major outages planned at Darlington. Overall, we expect future earnings volatility to come primarily from forecast risk as part of the regulatory process.

Financial Information

	For the year ended December 31				
	2024	**2023**	**2022**	**2021**	**2020**
Cash flow/total debt (%)	23.5	31.3	31.3	31.3	31.8
Total debt in capital structure (%)[1]	35.7	34.0	35.2	36.5	39.6
EBIT gross interest coverage (times)	3.25	5.37	5.35	4.73	5.00

1 Adjusted for Accumulated Other Comprehensive Income.
Note: Morningstar DBRS no longer excludes nonrecourse debt in its calculation of key metrics.

Issuer Description

OPG is an electricity generation company with a diverse portfolio of more than 18,000 MW of in-service generating capacity. The Company is wholly owned by the Province.

Business Risk Assessment

1. Reasonable regulatory framework that provides stable cash flow

The reasonable regulatory framework has allowed OPG to recover prudently incurred costs and provided stable cash flows. We note, however, that there have been disallowances by the OEB in the past on labour compensation costs related to the Company's nuclear operations. We also note that, under an incentive rate-setting (IR) framework and the regulated hydroelectric rate freeze, OPG's profitability could come under further pressure because of the need to meet efficiency and productivity benchmarks.

2. Support of shareholder (the Province)

The Province indirectly provides OPG with some of its long-term funding requirements through the Ontario Electricity Financial Corporation (OEFC; rated AA with a Stable trend), a government financing arm for provincial power companies. As at December 31, 2024, OPG had approximately $2.1 billion of notes payable to the OEFC, comprising 18% of the Company's outstanding debt. We believe that the Province will continue to support its investment because OPG is a creation of the Province and is integral to fulfilling Ontario's energy needs. OPG's importance in Ontario is also demonstrated by the fact that it is the primary electricity generator in Ontario, accounting for approximately 57% of electricity produced in 2024. While OPG's debt is not directly guaranteed by the Province, we believe that the Province will, in exceptional circumstances, provide support to the Company.

3. Nuclear generation risks

Nuclear generation, which represented approximately 40% of OPG's production in 2024, faces higher operating risks than other types of power generation because of its complex technology. The financial implications of forced outages are greater, given the high fixed-cost nature of these plants and because lost revenues resulting from outages are not recoverable through rates.

4. Political intervention

OPG is subject to political intervention, largely because of its ownership by the Province and changes in government mandates and policies. We note that, though the Province has committed to having the Company run more autonomously, the risk of further government intervention still exists. In November 2021, the OEB issued a decision to freeze OPG's regulated hydroelectric base rates at the 2021 level for the following regulatory period of 2022–26. We expect the Company's earnings to be modestly pressured as OPG will have to find efficiencies to offset inflationary cost increases.

5. Exposure to nonregulated operations

OPG owns several nonregulated generation assets, including gas-fired plants in Ontario and a renewable facility operator and developer in the U.S. The Company also owns nonregulated natural gas, oil, solar, and biomass generation assets in the Province. While the Ontario assets are largely under long-term contracts with strong investment-grade counterparties, such as the IESO, and contribute relatively stable

earnings and cash flow, we view nonregulated assets as generally having higher business risks than the incumbent regulated operations because there is less cost recovery certainty and potentially more volatile cash flow.

We note earnings contributed by regulated operations may fluctuate over the near term, resulting in nonregulated earnings to be near or modestly more than the 20% threshold as the ongoing Darlington Refurbishment project and the expected Pickering Refurbishment constrict output. The Company has indicated that growth in its nonregulated business will be at a more moderate pace going forward, with most planned capex for its regulated operations. As such, contributions from regulated operations are likely to remain higher than 80% over the long term, especially once the Darlington Refurbishment is completed in 2026. Additionally, we also consider assets under regulatory-styled contracts to have similar credit risks as regulated operations because those contracts mimic the current regulatory construct under the OEB; we estimate an EBITDA contribution of 86% from regulated operations and assets under regulatory-styled contracts in 2024. Examples of such assets include Lower Mattagami Energy Limited Partnership (LMELP; rated A (high) with a Stable trend), PSS Generating Station LP (New Post Creek) (PSS; rated A (low) with a Stable trend), and UMH Energy Partnership (UMH). However, should OPG pursue acquisitions that result in a significant shift in the EBITDA mix between regulated and nonregulated operations, or lead to credit metrics deteriorating to a level no longer supportive of the current rating category, we could take a negative credit rating action.

6. Tariff impact

OPG has low exposure to potential tariff risks because of its strong reliance on Canadian-based labour and suppliers, with over 90% of nuclear and hydroelectric procurement sourced domestically. OPG has established an internal Tariff Taskforce and is promoting made-in-Canada technologies. The Company's key projects are part of its regulated operations; financial exposure from tariff-related costs variances may be recoverable through regulatory deferral accounts.

Financial Risk Assessment

1. Significant capex program

OPG has a significant capex program under way, with approximately $12.7 billion planned for 2025–26. We note that OPG has started the initial preparation work to refurbish four units at the Pickering GS. The recent granting of the construction licence paves the way for major progress on the Darlington SMR project in the next two or three years. These two projects would be complex undertakings and require significant financing. While capex for both these projects will be regulated and should lead to a substantial increase in the rate base, there is also considerable execution risk, which could lead to large cost overruns. We are encouraged by OPG's current track record with the Darlington Refurbishment, which remains on budget and on schedule. We also expect that the Company will not undertake any major capex without having financing and a cost-recovery mechanism in place, thus minimizing financial risks.

2. High cost base

OPG's high cost base has resulted in several disallowances by the OEB. For the 2022–26 rates decision, the Company agreed, in a settlement proposal with intervenors, to reduce its non-Darlington-Refurbishment-related regulated nuclear operations, maintenance, and administration (OM&A) budget by 3% annually: a total of $277 million over the five-year term. We believe that OPG's inability to fully recover compensation costs in future regulated prices could have a negative impact on earnings and affect the Company's ability to achieve its approved return on equity (ROE).

3. Limited nuclear waste management liabilities

We note that the used fuel obligation is funded by the Nuclear Segregated Funds, which were overfunded as at December 31, 2024. The Province provides a guarantee to the CNSC as required, should there be a shortfall between the value of the Nuclear Segregated Funds and the CNSC consolidated financial guarantee requirement.

Environmental, Social, and Governance (ESG) Checklist

ESG Factor		ESG Credit Consideration Applicable to the Credit Analysis: Y/N		Extent of the Effect on the ESG Factor on the Credit Analysis: Relevant (R) or Significant (S)*
Environmental		**Overall:**	**N**	**N**
	Emissions, Effluents, and Waste	Do we consider that the costs or risks for the issuer or its clients result, or could result, in changes to an issuerÆs financial, operational, and/or reputational standing?	**N**	**N**
	Carbon and GHG Costs	Does the issuer face increased regulatory pressure relating to the carbon impact of its or its clients' operations resulting in additional costs and/or will such costs increase over time affecting the long-term credit profile?	**N**	**N**
	Resource and Energy Management	Does the scarcity of sourcing key resources hinder the production or operations of the issuer, resulting in lower productivity and therefore revenues?	**N**	**N**
	Land Impact and Biodiversity	Is there a financial risk to the issuer for failing to effectively manage land conversion, rehabilitation, land impact, or biodiversity activities?	**N**	**N**
	Climate and Weather Risks	In the near term, will climate change and adverse weather events potentially disrupt issuer or client operations, causing a negative financial impact? In the long term, will the issuer's or client's business activities and infrastructure be materially affected financially under key IPCC climate scenarios up to a 2°C rise in temperature by 2050?	**N**	**N**
Social		**Overall:**	**N**	**N**
	Social Impact of Products and Services	Do we consider that the social impact of the issuer's products and services pose a financial or regulatory risk to the issuer?	**N**	**N**
	Human Capital and Human Rights	Is the issuer exposed to staffing risks, such as the scarcity of skilled labour, uncompetitive wages, or frequent labour relations conflicts, that could result in a material financial or operational impact?	**N**	**N**
		Do violations of rights create a potential liability that can negatively affect the issuer's financial wellbeing or reputation?	**N**	**N**
		Human Capital and Human Rights:	**N**	**N**
	Product Governance	Does failure in delivering quality products and services cause damage to customers and expose the issuer to financial and legal liability?	**N**	**N**
	Data Privacy and Security	Has misuse or negligence in maintaining private client or stakeholder data resulted, or could it result, in financial penalties or client attrition to the issuer?	**N**	**N**
	Occupational Health and Safety	Would the failure to address workplace hazards have a negative financial impact on the issuer?	**N**	**N**
	Community Relations	Does engagement, or lack of engagement, with local communities pose a financial or reputational risk to the issuer?	**N**	**N**
	Access to Basic Services	Does a failure to provide or protect with respect to essential products or services have the potential to result in any significant negative financial impact on the issuer?	**N**	**N**
Governance		**Overall:**	**N**	**N**
	Bribery, Corruption, and Political Risks	Do alleged or actual illicit payments pose a financial or reputational risk to the issuer?	**N**	**N**
		Are there any political risks that could affect the issuer's financial position or its reputation?	**N**	**N**
		Bribery, Corruption, and Political Risks:	**N**	**N**
	Business Ethics	Do general professional ethics pose a financial or reputational risk to the issuer?	**N**	**N**
	Corporate / Transaction Governance	Does the issuer's corporate structure allow for appropriate board and audit independence?	**N**	**N**
		Have there been significant governance failures that could negatively affect the issuer's financial wellbeing or reputation?	**N**	**N**
		Does the board and/or management have a formal framework to assess climate-related financial risks to the issuer?	**N**	**N**
		Corporate / Transaction Governance:	**N**	**N**
		Consolidated ESG Criteria Output:	**N**	**N**

ESG Considerations

Environmental

There were no Environmental factors that had a relevant or significant effect on the credit analysis. OPG is actively addressing transition risks by implementing its Climate Change Plan, which includes a comprehensive strategy to mitigate potential impacts on the organization. The Company also invests in resilient infrastructure, enhances emergency preparedness, and adopts advanced technologies to improve operational efficiency. We note that OPG operates the Darlington and Pickering GSs, which create nuclear by-products such as used fuel and low- and intermediate-level materials. OPG's nuclear operations and handling of nuclear by-products are regulated by the CNSC. The Company also has nuclear fixed-asset removal and nuclear waste management funds for costs to be incurred for the safe storage of nuclear materials and for the eventual dismantlement of the facilities and remediation of the land. As at December 31, 2024, the Decommissioning Segregated Fund was overfunded by 47% and the Used Fuel Segregated Fund was overfunded by 10%. We expect costs associated with OPG's handling of nuclear by-products to be funded through regulated rates.

Social

There were no Social factors that had a relevant or significant effect on the credit analysis. We note that, as a regulated utility, OPG provides an essential service. Any significant unplanned outages in the Company's operations could affect its reputation and could impact financial performance. OPG's nuclear operations are regulated by the CNSC to ensure compliance with nuclear facility security measures, environmental matters, and safety operations. The Company is subject to audits and inspections against CNSC licence and performance objectives. Canada is also signatory to various international conventions relating to nuclear energy and emergency responses. OPG is also committed to workplace health and safety, using an integrated health and safety management system and operational risk control procedures. As many of the Company's generation assets are within the treaty and traditional territories of Indigenous peoples, OPG also has an Indigenous Relations Policy and Reconciliation Action Plan (RAP) to engage and collaborate with Indigenous communities across the Province. Since 2022, OPG has reached $198 million in Indigenous contract awards and $39.4 million in equity distributions to the Indigenous partners. The RAP committed the Company to grow its economic impact on Indigenous communities and businesses to $1 billion over 10 years.

Governance

There were no Governance factors that had a relevant or significant effect on the credit analysis. OPG has a Memorandum of Agreement (MOA) with its shareholder, the Province, on the governance, performance, and communications of the Company. The MOA underlines the Province's expectation that OPG's board of directors is responsible for overseeing management of the Company, which operates as a business enterprise with a commercial mandate. OPG's president and chief executive officer has a seat on the board. All other board members are independent. The board is responsible for approving numerous ESG-related policies for the Company, including those on environmental, diversity and inclusion, business conduct, conflict of interest, and cybersecurity.

Credit Rating History

	Current	2024	2023	2022	2021	2020
Issuer Rating	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Unsecured Debt	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

Previous Report

- *Ontario Power Generation Inc.: Rating Report*, April 30, 2024

Previous Actions

- Morningstar DBRS Confirms Ontario Power Generation Inc. at A (low)/R-1 (low), Stable Trends, April 11, 2024

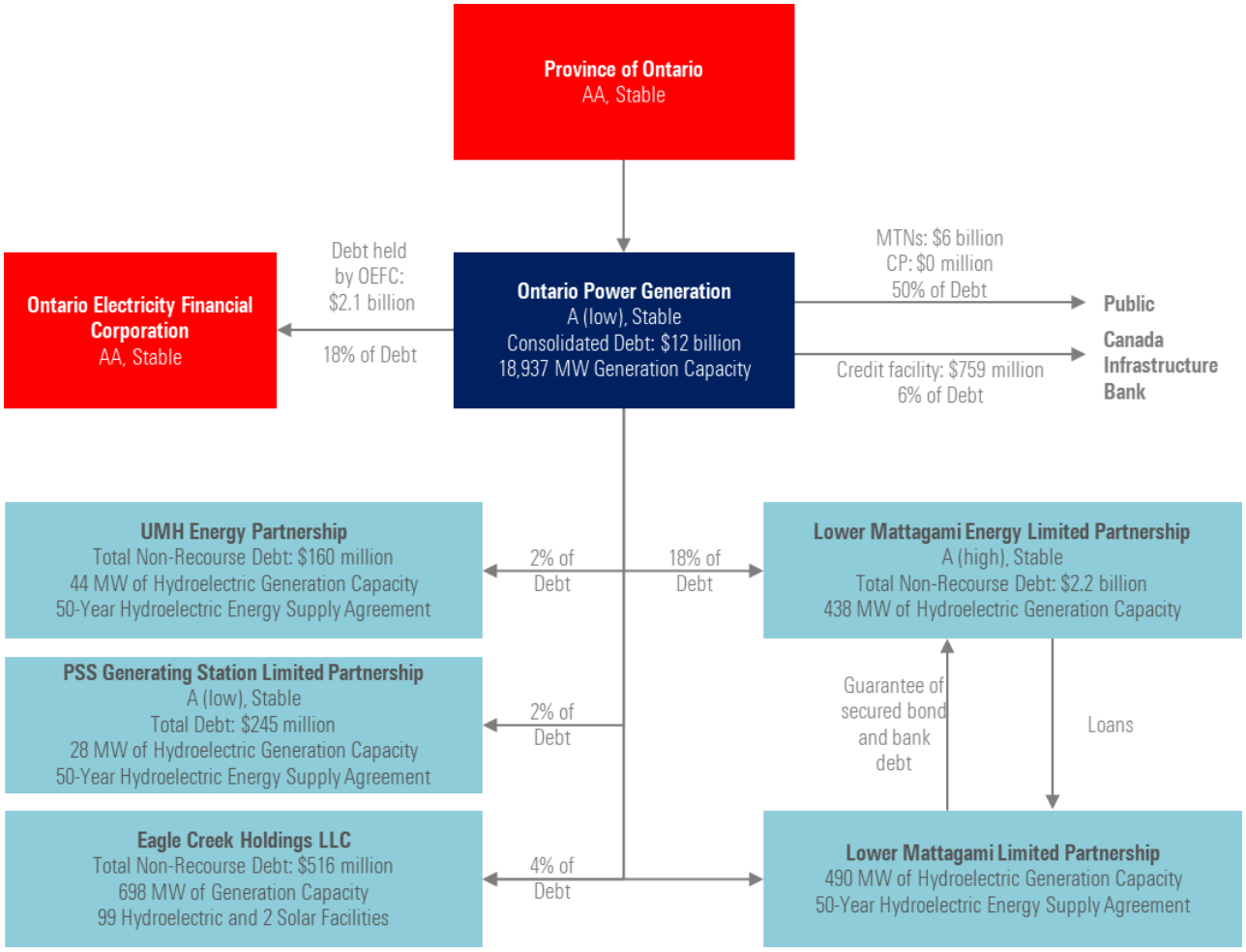
Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on https://dbrs.morningstar.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

Appendix 1—Company Profile

Exhibit 1 Organizational Chart



As at December 31, 2024.
Source: OPG.

- As at December 31, 2024, debt at the OPG corporate level consists of $2.1 billion held by the OEFC, $6 billion of medium-term notes, and $759 million drawn under a credit facility provided by the Canada Infrastructure Bank.
    - Debt at UMH, LMELP, and Eagle Creek Holdings LLC (Eagle Creek) are secured by the assets at each corresponding subsidiary and are nonrecourse to the Company.
    - Debt at PSS is recourse to OPG until the recourse release date.

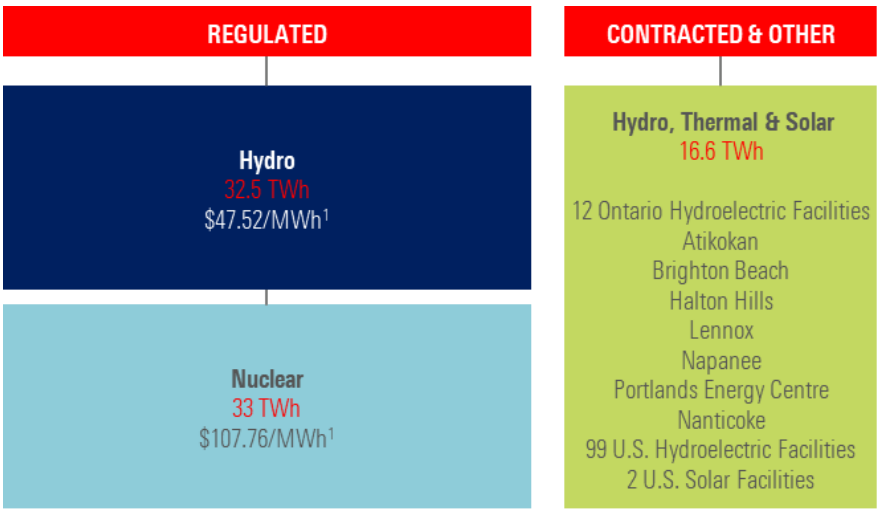
In-Service Generation Profile

As at December 31, 2024	Percent (%)	Capacity (MW)
Nuclear		
Darlington	15	2,634
Pickering	11	2,064
	26	**4,698**
Thermal		
Atikokan (Biomass)	1	180
Lennox (Dual oil & gas)	12	2,100
Atura Power[1]	15	2,715
	28	**4,995**
Hydroelectric		
Contracted[2]	10	1,756
Regulated	36	6,566
	46	**8,322**
Other		
Solar[3]	0	44
Total Capacity	**100**	**18,059**

1 Includes four facilities.
2 Includes plants under an Energy Supply Agreement (ESA) or a long-term contract.
3 Three solar facilities.

- OPG is the largest generator of electricity in Ontario. In 2024, the Company generated 82.1 terawatt hours of electricity.
- OPG also owns the Bruce A and Bruce B Nuclear GSs, which are leased on a long-term basis to Bruce Power L.P. (rated BBB with a Positive trend).

Exhibit 2 Price Structure



1 Rates as of January 1, 2025.
For the year ended December 31, 2024.
Source: OPG.

- OPG sells electricity to consumers through the IESO.
- Regulated facilities sell at rates set by the OEB, which could include rate riders used for the recovery of nuclear deferral and hydroelectric variance account balances.
- The Contracted and Other Portfolio includes (1) assets in Ontario that sell electricity at prices set through ESAs or other long-term contracts with the IESO and (2) Eagle Creek, which holds interest in 99 U.S. hydroelectric GSs and two U.S. solar facilities.
    - The Eagle Creek facilities either sell into the merchant market or operate under long-term energy or capacity supply contracts.

Appendix 2—Major Projects

Project	Estimated Cost (CAD millions)	Spent as of Dec. 31, 2024 (CAD millions)	In-Service Target Date
Darlington Refurbishment	12,800	11,190	2026[1]
Smoky Falls Dam Safety Project	390	327	2025[2]
Atura Power Development Projects	1,500	288	2026-2028[3]

1 Four units with staged in-service. Last unit scheduled to be completed by 2026.
2 The project has transitioned to site rehabilitation and closure activities, which will continue into 2025.
3 Scheduled completions: Niagara Hydrogen Centre – 2026; Napanee BESS – 2026; Napanee Combined Cycle GS Expansion Project – 2028.

- **Darlington Refurbishment**: The Darlington Refurbishment will extend the operating life of the Darlington GS by at least 30 years. The execution of the refurbishment of the first unit began in October 2016, and the last unit is scheduled to be completed by 2026. Construction on the first unit was completed in March 2020, and it returned into service in June 2020. Refurbishment on the second unit began in September 2020, after a short delay related to the coronavirus pandemic, and was placed back in service in July 2023, ahead of schedule. Refurbishment on the third unit began in February 2022 and was completed in November 2024, five months ahead of schedule. Refurbishment on the fourth unit began in July 2023 and the unit is scheduled to be returned to service by the end of 2026. The project remains on schedule and on budget.
- **Smoky Falls Dam Safety Project**: This project is intended to improve dam safety at the Smoky Falls hydroelectric GS. The major construction activities were completed in 2024.
- **Atura Power Development Projects**: The projects include (1) the construction of an electrolyzer for large-scale hydrogen production using hydro power in Niagara Falls, Ontario; (2) a 250 MW BESS at the Napanee GS site; and (3) a Napanee GS Expansion to add a hydrogen-ready simple-cycle combustion turbine generator unit that will provide up to 405 MW of electricity output to Ontario's electricity grid.
- **Pickering Refurbishment**: In June 2023, OPG applied to the CNSC to extend the life of the Pickering Nuclear GS to September 2026. In January 2024, the Province approved for the Company to begin engineering and design work and to secure long-lead components to refurbish four units of the Pickering Nuclear GS to extend the operating life by at least 30 years.
- **Darlington New Nuclear Project**: This project involves constructing Canada's first grid-scale SMR at the Darlington site. In July 2023, the Province announced for the Company to proceed with planning and licensing for three additional SMRs at the Darlington site, with in-service dates in the mid-2030s. On April 4, 2025, the CNSC granted OPG a licence to construct one SMR.

Appendix 3—Regulation

- OPG benefits from a reasonably regulated environment. As at December 31, 2024, approximately 63% of its installed in-service capacity was regulated.
    - OPG, regulated by the OEB under the Ontario Energy Board Act, 1998, is allowed to receive regulated prices for all electricity generated from its nuclear facilities (4,850 MW) as well as most of its hydroelectric power facilities in Ontario (6,565 MW).
- In November 2021, the Province amended Ontario Regulation (O. Reg.) 53/05 (O. Reg. 53/05) to freeze hydroelectric base rates for OPG at the 2021 level for the next regulatory period of 2022–26.
    - Morningstar DBRS notes the hydroelectric rate freeze may modestly pressure the Company's earnings as OPG will have to find efficiencies in its regulated hydroelectric operations to offset inflationary cost increases.
    - The next rate application will be filed before the end of 2025 and will be effective on January 1, 2027.
- In November 2021, the OEB issued its decision on OPG's application for rates effective January 1, 2022.
    - The OEB approved a settlement proposal between OPG and intervenors as filed.
    - As per O. Reg. 53/05, hydroelectric base payment amounts will remain at the 2021 level.
    - Capital structure will remain at 55% debt (the Company had requested a change to 50% debt) and an allowed ROE of 8.66%.
    - For nuclear facilities, the continuation of the current Custom IR methodology along with a rate-smoothing deferral account (as required under O. Reg. 53/05).
    - Under Custom IR, nuclear revenue requirements were determined by a five-year forecast cost-of-service (COS) approach, but with a stretch factor of 0.6% applied to the Company's OM&A expenditures for 2023–25, compared with 0.45% as requested, and 0.3% for 2026. The reduction in OM&A costs as a result of the stretch factor will accumulate for the five-year period.
    - The rate-smoothing deferral account will stabilize year-to-year changes to weighted-average payment amounts as the Darlington Refurbishment continues. OPG will defer a portion of its approved nuclear revenue requirements into the rate-smoothing deferral account and will be allowed to recover the deferred amount over a 10-year period once the Darlington Refurbishment has been completed.
    - Total regulated nuclear revenue requirement of $16.0 billion over the five-year term, representing a $567 million reduction (including a 3%, or $277 million, reduction of OM&A costs) from the Company's application.
    - The OEB approved the inclusion of $8.6 billion to the rate base, including $6.4 billion for the Darlington Refurbishment, over the five-year period of the Custom IR, representing a reduction of $298 million for planned non-Darlington Refurbishment in-service capital add-ons. Any Darlington Refurbishment cost overruns will be subject to a prudence review before being added to the rate base.

- Inclusion of $396 million to the rate base for the Heavy Water Storage and Drum Handling Facility project (in-service 2020); this represents a permanent rate base reduction for the project of $94 million plus carrying costs incurred from May 2017 to March 2020 for capital costs deemed not prudently incurred.
- Recently completed non-Darlington Refurbishment capex of $358 million, which exceeded the 2017–21 approved in-service capital additions, will earn an ROE at the cost of long-term debt (3.6% for the 2022 to 2026 rate period) instead of the allowed ROE until 2037.
- The OEB approved the recovery of balances as at December 31, 2019, in OPG's deferral and variance accounts. The OEB also approved a $47 million credit to customers for the impact of favourable electricity revenue during the 2020 and 2021 coronavirus pandemic response (net of any incremental pandemic-related OM&A).
- All previously existing regulatory accounts will continue, along with new accounts to track (1) any financial impact from a possible transition to and implementation of International Financial Reporting Standards from U.S. Generally Accepted Accounting Principles, (2) revenue requirement impact for a planned new corporate campus, and (3) any revenue requirement impact to nuclear liabilities and depreciation expense from accounting end-of-life assumptions for the Pickering GS.
- An earnings-sharing mechanism was also approved, where regulated earnings 100 basis points above the approved ROE over the cumulative five-year term will be shared 50/50 with customers.

Approved Regulated Nuclear Amounts	2022	2023	2024	2025	2026
Nuclear revenue requirement (CAD millions)	3,515.5	3,430.0	3,518.3	3,197.6	2,439.5
Nuclear rate base (CAD millions)	8,600.3	8,615.0	11,033.4	12,188.8	12,991.8
Nuclear payment amount (CAD per MW hour (MWh))	105.22	109.04	104.63	108.19	118.91
Hydro payment amount (CAD per MWh)	44.91	44.91	44.91	44.57	44.57

- In June 2023, OPG filed an application with the CNSC to extend operating Pickering GS to September 2026.
    - In December 2022, the Province amended O. Reg. 53/05 to require OPG to establish a variance account to track the additional revenues and costs associated with operating Units 5 to 8 of the Pickering GS between January 1 and September 30, 2026. The disposition of the account balance will be subject to the OEB's prudence review and approval in a future proceeding.
- On April 4, 2025, the CNSC granted OPG a licence to construct a BWRX-300 SMR at the Darlington New Nuclear Project (DNNP) site. This marks the first licence issued for the construction of a grid-scale SMR in Canada. The 10-year licence is valid until March 31, 2035, and includes conditions for oversight and compliance. The decision followed a two-step public hearing in 2024–25 and reflects the CNSC's conclusion that OPG can construct the SMR safely.

Assessment of Regulatory Framework

Criteria	Score	Analysis
1. Deemed Equity	Excellent **Good** Satisfactory Below Average Poor	The OEB allows OPG to have a deemed equity of 45%.
2. Allowed ROE	Excellent Good **Satisfactory** Below Average Poor	OPG has an allowed ROE of 8.66% for 2022–26 (based on nuclear regulated rates), which is in line with the other regulated utilities in Ontario. Any difference in ROE between the Company and other regulated utilities in the Province is mainly because of the timing of the regulatory filings and the interest rate environment prevalent at that time.
3. Energy Cost Recovery	Excellent Good Satisfactory Below Average Poor	N/A; energy costs are recovered through rates for OPG.
4. Capital and Operating Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	Under Custom IR for the nuclear facilities, the capex program for OPG is preapproved for a five-year period by the OEB and recovered through base rates. Future test years are used for nuclear rates applications. Some volume risk exists, but this is partly mitigated by (1) use of deferral accounts for volumetric differences and (2) the fact that rates are based on forecasts that include scheduled outages. However, lost revenues resulting from forced outages beyond the forecast allowances are not recoverable through rates.
5. COS versus IRM	Excellent Good **Satisfactory** Below Average Poor	The nuclear facilities operate under Custom IR, which is a hybrid of COS and the IR framework, for a five-year term. We consider the Custom IR framework as reasonable.
6. Political Interference	Excellent Good Satisfactory **Below Average** Poor	The Government of Ontario plays a significant role in the electricity sector in Ontario, given that most of the utilities are government owned (OPG is owned by the Province). Furthermore, stakeholders, such as the IESO, are also government owned. As a result, the government has direct and indirect influence on Ontario's electricity industry as evidenced by the rate freeze on hydroelectric base rates in 2021.
7. Stranded Cost Recovery	Excellent Good **Satisfactory** Below Average Poor	Regulated utilities in Ontario have a limited history of stranded costs. Most prudently incurred or budgeted capex is approved by the OEB. While OPG has seen some write-downs, these have been because the OEB deemed the costs overruns to have been imprudent.
8. Rate Freeze	Excellent Good Satisfactory **Below Average** Poor	In November 2021, the Province amended O. Reg. 53/05 to freeze hydroelectric base rates for the Company at the 2021 level for the next regulatory period from 2022 to 2026. Rates for nuclear facilities were not frozen and have been set by the OEB. We note that the hydroelectric rate freeze may modestly pressure OPG's earnings as the Company will have to find efficiencies to offset inflation.

Appendix 4—Long-term Debt and Credit Facilities

Long-term Debt

(CAD millions as at December 31, 2024)	Maturity	Amount
OEFC + Corporate Credit Facilities	2026–48	2,859
Medium Term Note Program	2025–54	5,950
UMH[1]	2041	160
PSS[2]	2067	245
LMELP[1]	2026–54	1,995
Eagle Creek[1]	2025–30	516
Other		25
Subtotal		**11,750**
Less: Bond issuance fees		(43)
Less: Current portion		(604)
Total long-term debt		**11,103**

1 Nonrecourse to OPG as debt is secured by assets of the associated project.
2 Secured by assets of the projects; recourse to OPG until the recourse release date.

- Debt at UMH, LMELP, and Eagle Creek are secured by assets of the associated project and nonrecourse to OPG. Debt at PSS is secured by assets of the project and are recourse to OPG until the recourse release date.

Maturity Profile

(CAD millions as at December 31, 2024)	2025	2026	2027	2028	2029	Thereafter	Total
Long-term debt	604	674	530	269	505	9,168	**11,750**
	5%	6%	5%	2%	4%	78%	**100%**

- OPG's maturity profile is fairly spread out.

Credit Facilities

(CAD millions as at December 31, 2024)	Maturity	Amount	Drawn/LOC	Available
Committed credit facility	May 2029	1,000	0	1,000
Committed credit facility–USD 750 million	Nov. 2025	1,079	0	1,079
OEFC general corporate credit facility	Dec. 2026	750	0	750
OFA[2] general corporate credit facility	Dec. 2029	1,250	0	1,250
Canada Infrastructure Bank term credit facility[3]	Jul. 2025	970	759	211
Short-term uncommitted credit facilities	Demand	677	430	247
Short-term uncommitted overdraft facilities	Demand	25	0	25
Lower Mattagami River Project[1]	Aug. 2028	460	60	400
UMH credit facilities[1]	Oct. 2025	16	14	2
UMH overdraft facilities[1]	Oct. 2025	8	0	8
Eagle Creek credit facility—USD 20 million[1]	Oct. 2028	29	0	29
Subtotal		**6,264**	**1,263**	**5,001**
CPs—corporate			0	0
CPs—LMELP			215	(215)
Total		**6,264**	**1,478**	**4,786**

1 Nonrecourse to OPG as debt is secured by assets of the associated project.
2 OFA: Ontario Financing Authority.
3 The facility is made available to fund part of the expenditures required to prepare for the construction of OPG's first SMR at the DNNP sites. The facility is expected to mature in July 2025.
Note: CP=commercial paper.

- OPG has a reasonable liquidity profile.
- The Company has a $1.0 billion Canadian commercial paper (CP) program (none outstanding as at December 31, 2024) and a USD 750 million CP program in the U.S. (none outstanding as at December 31, 2024). These CP programs are supported by the following facilities:
    - Committed bank facility of $1.0 billion (due date of May 2029);
    - A USD 750 million bank facility (due date of November 2025, with a one-year term-out option);
    - An OEFC facility of $750 million (due date of December 2026); and
    - An OFA facility of $1,250 million (due date of December 2029).
- The LMELP, UMH, and Eagle Creek facilities are used to support the respective projects and are nonrecourse to OPG.

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MOODY'S
RATINGS

Announcement of Periodic Review: Moody's Ratings announces completion of a periodic review of ratings of Ontario Power Generation Inc.

20 May 2025

Toronto, May 20, 2025 -- Moody's Ratings (Moody's) has completed a periodic review of the ratings of Ontario Power Generation Inc. and other ratings that are associated with this issuer.

The review was conducted through a rating committee held on 15 May 2025 in which we reassessed the appropriateness of the ratings in the context of the relevant principal methodology(ies), and recent developments.

This publication does not announce a credit rating action and is not an indication of whether or not a credit rating action is likely in the near future. Please see the Issuer page on https://ratings.moodys.com for the most updated credit rating action information and rating history.

Key Rating considerations and rationale are summarized below.

Ontario Power Generation's (OPG) ratings, including its A3 senior unsecured rating, and stable outlook remain unchanged. OPG's A3 rating reflects a Baseline Credit Assessment (BCA) of baa3 with a 3 notch uplift based on its high dependence on and a high probability of extraordinary support from the Province of Ontario (Aa3 positive).

OPG is wholly owned by the Province of Ontario and is considered a government related issuer (GRI) under our GRI methodology. The three notch uplift attributed to OPG as a GRI incorporates our expectation of an enduring link between OPG and the Province. Our high support assumption considers that OPG produces more than half of the power generated in the Province at a comparatively low cost, making its infrastructure essential to the Ontario economy. OPG also implements government policies, its board is appointed by the Province, and crown corporations are a source of debt capital for the company. Our assessment of high dependence reflects that both OPG and the Province largely rely on the same revenue base and share some political risks.

OPG's credit profile benefits from its substantial regulated nuclear and hydroelectric operations that typically generate the vast majority of its relatively stable cash flow. The majority of OPG's contracted assets generally exhibit long contract tenors with a strong counterparty in the Ontario Independent Electricity System Operator (IESO, Aa3 positive) to which most assets are contracted and to which they pass through most of their costs. The company benefits from a diverse portfolio of generation including nuclear, hydroelectric, natural gas-fired and renewable energy resources across its extensive fleet.

Offsetting these credit strengths, OPG has a large capital expenditure program that has very high levels of execution risk particularly with nuclear investments. OPG continues to exceed our expectations on its Darlington nuclear refurbishment by completing its most recent unit five months ahead of schedule. OPG's experience and lessons learned at Darlington could position the company well as it embarks on the refurbishment of Units 5-8 of the Pickering nuclear generating station that the company is moving forward with subject to final approvals.

The Province recently approved OPG's plan to begin construction on its a CAD20.9 billion small modular reactor (SMR) program at Darlington which carries very high levels of execution risk.

The approval only applies to the first unit which has a total budget of 7.7 billion. OPG expects the first of four units to be in commercial operation in 2029 and connected to the grid in 2030. While we expect these units to be part of its regulated power generation fleet, at this time it is uncertain how much regulatory support, if any, the company will have during the Pickering refurbishment as well as the construction of SMR program.

Although OPG is in the midst of an elevated capital investment program, we continue to expect the company's cash flow before changes in working capital to debt ratio to be sustained in the 16-21% range over the next few years. OPG does not pay a dividend and reinvests all of its cash flow into maintaining and growing its asset base.Similar to investor-owned utilities, we expect OPG to consider multiple levers to finance its large capital plan, including the potential sale of non-core assets, equity, hybrid securities in addition to debt issuances. The company is exposed to availability risk across its fleet of generation assets and some hydrology risk. While small, its merchant generation segment has grown as a result of several wholly-debt financed acquisitions, however, we expect OPG's large capital program lessens the probability of additional, materially debt financed M&A transactions.

As a result of the elevated capital program some of which has very high levels of execution risk and uncertainty over the funding program, the governance score was changed to Moderately Negative (G-3 Issuer Profile Sore, or IPS) from Neutral-to-low (G-2 IPS).

This document summarizes our view as of the publication date and will not be updated until the next periodic review announcement, which will incorporate material changes in credit circumstances (if any) during the intervening period.

The principal methodologies used for this review were Government-Related Issuers methodology published in January 2024 and Regulated Electric and Gas Utilities published in August 2024. Please see the Rating Methodologies page on https://ratings.moodys.com for a copy of these methodologies.

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MOODY'S RATINGS

CREDIT OPINION
30 June 2025

Update

Send Your Feedback

RATINGS

Ontario Power Generation Inc.

Domicile	Ontario, Canada
Long Term Rating	A3
Type	Senior Unsecured - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Ontario Power Generation Inc.

Update to credit analysis

Summary

Ontario Power Generation's (OPG) credit profile reflects a Baseline Credit Assessment (BCA) of baa3 with a 3 notch uplift based on its high dependence on and a high probability of extraordinary support from the Province of Ontario (Aa3 stable).

OPG's credit profile benefits from its substantial regulated nuclear and hydroelectric operations that are expected to generate the vast majority of its relatively stable cash flow. OPG's contracted assets generally exhibit long contract tenors and have a strong counterparty in the Ontario Independent Electricity System Operator (IESO, Aa3 stable) to which most assets are contracted and to which they pass through most of their costs. The company also has diversification benefits across its extensive fleet.

Offsetting these credit strengths, OPG has a large capital program that has very high levels of execution risk associated with some nuclear capital expenditures. OPG has exceeded our expectations on its Darlington nuclear refurbishment by completing its most recent unit about 5 months ahead of schedule. The company's success at Darlington may carry over as it moves forward with the refurbishment of units 5-8 of the Pickering nuclear generating station as well.

The company has also begun construction on a CAD20.9 billion small modular reactor (SMR) program at Darlington which carries very high levels of execution risk. OPG expects the first of four potential units to be in commercial operation in 2030. While we expect all of these units to form part of its regulated fleet, at this time it is unclear what the extent of the regulatory support, if any, the company will have for the Pickering refurbishment and the SMR program during construction, although the government has solicited feedback on credit friendly measures.

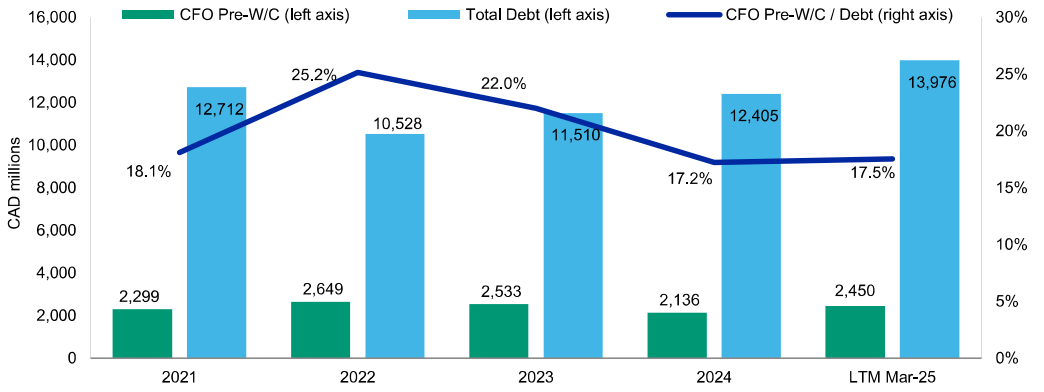
We expect the company's CFO pre-W/C to debt ratio to be sustained in the 15%-20% range over the next few years. OPG does not pay a dividend and reinvests all of its cash flow into maintaining and growing its asset base, although we expect debt to grow to fund its capital program. The company is exposed to availability risk across its fleet of generation assets and some hydrology risk. While small, its merchant generation segment has grown in the past as a result of several 100% debt financed acquisitions and we think OPG's large capital program diminishes the probability of additional, material debt financed M&A transactions.

OPG is 100% owned by the Province of Ontario and is considered a government related issuer (GRI) under our GRI methodology. The three notch uplift attributed to OPG as a GRI incorporates our expectation of an enduring link between OPG and the Province. Our high support assumption considers that OPG produces more than half of the power generated in the Province at a comparatively low cost, making its infrastructure essential to the Ontario economy. OPG also implements government policy, its board is appointed by the Province and the Ontario Electricity Financial Corporation (OEFC, Aa3 stable), a crown corporation, is

a source of debt capital for OPG. Our assessment of high dependence reflects that both OPG and the Province largely rely on the same revenue base and share some political risks.

Exhibit 1

Historical CFO Pre-W/C, Total Debt and CFO Pre-W/C to Debt



All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Periods are fiscal year-end unless indicated.
Source: Moody's Financial Metrics™

Credit strengths

» Primarily regulated generation facilities support stable cash flow generation

» Non-regulated generation segment dominated by long term contracts

» Our expectation of support from the Province of Ontario given its 100% ownership

» Diversification benefits by power generation site and units, as well as fuel source

Credit challenges

» Large capital program, which has very high levels of execution risk associated with some nuclear capital expenditures

» Uncertain regulatory support for large capital projects during construction

» Merchant cash flow entails more risk

» Availability risk across the fleet, including potential weak hydro conditions

Rating outlook

The stable outlook incorporates the following expectations:

» The company will continue to execute the Darlington nuclear refurbishment on time and budget

» It will maintain a CFO pre-WC/debt ratio in the 15-20% range over the next few years

» The relationship with the Province will remain stable and supportive

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the issuer/deal page on https://ratings.moodys.com for the most updated credit rating action information and rating history.

Factors that could lead to upgrade

» An upgrade is unlikely given the very high levels of execution risk associated with some of its upcoming nuclear capital expenditures

» CFO pre-WC/debt sustained above 20%

» An improvement in regulatory outcomes

» An upgrade of the Province to Aa1

Factors that could lead to downgrade

» Challenges, delays or cost overruns related to its capital program

» A reduction in the probability of support from the Province

» A deterioration in financial metrics such that CFO pre-WC/debt is forecast to fall below 15% on a sustained basis

» A weakening of the business risk profile by, for example, further growing the merchant segment

Key indicators

Exhibit 2

Ontario Power Generation Inc.

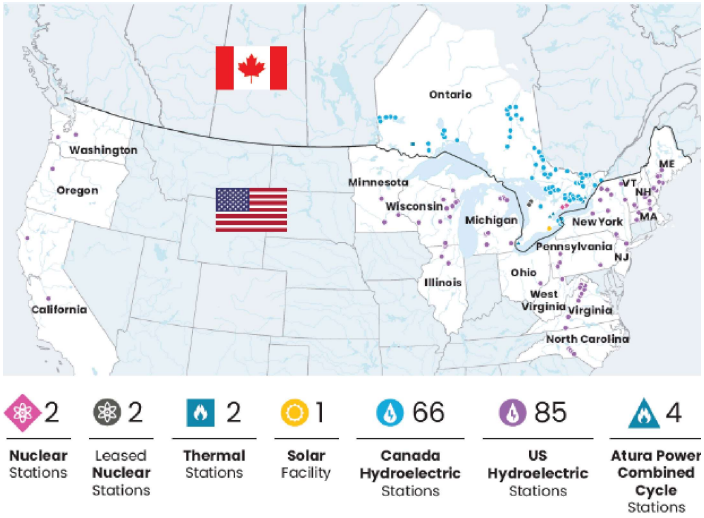
	2020	2021	2022	2023	2024	LTM Mar-25
CFO Pre-W/C + Interest / Interest	6.1x	5.8x	6.5x	7.2x	5.6x	6.2x
CFO Pre-W/C / Debt	17.0%	18.1%	25.2%	22.0%	17.2%	17.5%
CFO Pre-W/C – Dividends / Debt	16.8%	17.9%	25.0%	21.8%	17.1%	17.4%
Debt / Capitalization	47.9%	40.7%	33.6%	33.7%	34.0%	36.2%

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Periods are fiscal year-end unless indicated.
Source: Moody's Financial Metrics™

Profile

Headquartered in Toronto, Ontario, OPG is an electricity generation company wholly owned by the Province with an in-service generating capacity of 18,094 MW at 31 March 2025. OPG owns and operates 75 generating stations, 2 of which are nuclear, 66 hydroelectric, 2 thermal, 1 solar and 4 combined-cycle natural gas-fired plants in Ontario, Canada. In the US, OPG also wholly or jointly owns and operates 85 hydroelectric stations and has interests in 14 other hydroelectric and 2 solar facilities. OPG's nuclear and most of its hydroelectric facilities are regulated by the Ontario Energy Board (OEB).

Exhibit 3
OPG's service territory



Source: Company filings

Detailed credit considerations

Primarily regulated and contracted assets generate predictable cash flow

OPG's strong business risk profile is driven by its high proportion of regulated and contracted cash flow. Regulated earnings from OEB's rate regulated assets accounted for 73% of the EBITDA (all figures rounded) from its generating business segments during the LTM ending March 2025, including 45% from the regulated nuclear generation segment and 27% from the regulated hydroelectric generation segment. The Atura Power combined cycle plants generated 14% of EBITDA and contracted hydroelectric and other, which has more contracted cash flow than merchant, generated 14% of EBITDA.

The company has extensive diversity by generation station and unit within each segment, reducing volatility. It also has some hydro risk, albeit low, and negligible levels of commodity price risk, a key credit positive. Unlike most other regulated utilities, OPG owns generating assets only and does not have any lower risk transmission and distribution assets. As a result, as a higher risk generation company, OPG is exposed to availability risks on all of its assets which drives more variability in its financial results compared to most T&D companies.

The company's regulated assets should provide predictable cash flow going forward. A multiyear rate plan in place from 2022-2026 establishes volumetric prices for the regulated nuclear segment and a change in Ontario Regulation 53/05 undertaken by the Province provides pricing for regulated hydroelectric assets over this period.

The nuclear generation segment benefits from diversification across 2 nuclear generating stations, with 4 units at Pickering and 4 units at Darlington able to generate electricity absent shutdowns and refurbishments. This enables the company to maintain high levels of generation and cash flow while undertaking nuclear refurbishment. Pickering Units 1 and 4 were permanently shut down in Q4 2024.

In the second half of 2021, OPG reached a settlement with its intervenors that was subsequently approved by the OEB. The settlement led to a 2022-2026 nuclear generation revenue requirement of CAD16 billion, compared to CAD16.7 billion in the company's rate case application. Regulated prices are designed to support an allowed level of operating costs and earn a return on its capital costs for a forecast amount of generation. Significantly, the settlement supports growth in rate base over the period as the company continues to make progress on the Darlington refurbishment.

Nuclear rate base for the period 2022-2026 is allowed an ROE of 8.66% and hydroelectric 9.33% and both have equity capital of 45%. Performance that deviates by more than 300 bps in any given year may lead to a regulatory review. Regulatory lag has improved considerably with the most recent rate case, where a payments order was issued in January 2022 with new rates effective that month, although the extensive use of deferral accounts that reduce cash flow is a credit negative. Nuclear rates have significantly increased over the past several years. As recently as the first half of 2017, nuclear rates were CAD 59.29 MWh, a price that, like the table below,

incorporates rates riders for variance and deferral accounts. The table below includes rates increases to both nuclear and hydroelectric rates following a 13 June 2024 OEB decision that addressed several issues, including multiple variance accounts.

Exhibit 4

	2023	2024	2025	2026
Regulated Nuclear Generation Total price ($/MWh)	109.0	107.8	111.6	123.8
Approved Nuclear Rate Base (CAD million)	8,615.0	11,033.0	12,189.0	12,992.0
Forecast Nuclear Production (TWh)	31.2	34.0	31.1	21.9
Regulated Hydroelectric Generation price ($/MWh)	44.9	47.5	47.2	47.2

Rates for 2024-2026 effective 1 July 2024
Source: Ontario Energy Board

The regulated hydroelectric facilities include 54 generating stations in Ontario across a number of river systems with prices established by an incentive rate mechanism. On 10 November 2020, the Province took steps to establish the hydroelectric base regulated price for the period 2022-2026 at the 2021 regulated price. While this provides price certainty for the period, it challenges OPG to earn its allowed returns over the period given ongoing investments in rate base assets that exceed depreciation. Mitigating this challenge is the increase in production that will directly result from some of these investments.

The contracted hydroelectric and other generation segment consists of lower risk contracted assets in Ontario and higher risk, primarily merchant US based assets. Ontario based assets are all under contract on generally favorable terms and almost all of the contracts are with the IESO. The largest of these is the project financed Lower Mattagami Energy Limited Partnership (A1 stable). It, and other contracted hydro facilities like it, including UMH Energy Partnership (A2 stable), have strong contract terms which include limited hydro risk and contract expiries over the 2059-2067 period. The two Ontario thermal plants in this segment have substantial capacity, but are largely peaking facilities and typically have low levels of generation. They are primarily compensated based on their availability and have cost pass through provisions, however they have shorter contract tenors compared to the contracted hydro facilities.

The Atura Power business consists of 4 combined cycle gas plants that operate under contract with the IESO on similar terms to the above mentioned thermal plants. The latest contract expiry is the 900 MW Napanee plant that operates under a 20 year contract that expires in 2040. This segment includes a capacity agreement to build a 250MW four hour battery storage system at the site of one of its gas plants. It expects to complete construction in 2026 and the investment is supported by a 21 year capacity agreement with the IESO. The US assets have some contracts, but are primarily merchant assets with substantially more risk than the rest of the portfolio.

Large, nuclear focused capital program with varying degrees of execution risk

We expect OPG's large capital program to grow rapidly to about CAD5-7 billion a year with varying degrees of execution risk. Weighing on the company's business risk profile in particular is the risk associated with nuclear capex. The company's CAD20.9 billion small modular reactor program is at the very high end of the risk spectrum, with less risk associated with Pickering refurbishment and lower risk associated with the almost completed Darlington refurbishment. At this time, it is unclear what regulatory support, if any, the company will have for Pickering refurbishment and the SMR program during construction. However the government concluded a public comment period on 26 June 2025 where it was soliciting feedback on concurrent cost recovery for nuclear construction that would apply to both the SMR program and Pickering refurbishment and allow OPG to sell a portion of the SMR project to investors. Both measures would be credit positive for OPG, but the financial benefit depends on key assumptions. The company has not yet released a cost estimate for Pickering refurbishment. The ability to move forward with large projects without a public cost estimate and certainty on the degree of regulatory support during construction differentiates OPG from investor owned utilities.

Darlington refurbishment execution risk is diminishing

Execution risk associated with nuclear refurbishment at the Darlington Generation Station is diminishing given the company's strong track record of execution on the first 3 units. Unit 3 connected to the grid 169 days ahead of schedule, resulting in the production of an incremental 3TWh of electricity. Similarly the company returned Unit 1 to service 5 months ahead of schedule. The company applied more than 1000 lessons learned from Unit 2's refurbishment and applied those lessons learned to subsequent units. The company

continues to incorporate best practices and techniques into subsequent units. The refurbishment is tracking to its forecast cost of CAD12.8 billion.

The time table for Unit 4 is the second half of 2026, although we think there is a high probability that this unit will also return to service ahead of schedule based on the company's track record. The regulatory framework continues to incorporate the forecasted capex to bring the units in service, so it is already reflected in both rate base and revenues without the need for OPG to file a rate case.

Exhibit 5
Darlington refurbishment timeline

Darlington	Capacity	Refurbishment start date	Refurbishment completion date
Unit 2	878	Oct-16	Jun-20
Unit 3	878	Sep-20	Jul-23
Unit 1	878	Feb-22	Nov-24
Unit 4	878	Jul-23	H2-2026

Source: Company filings

Pickering refurbishment also moving forward but awaiting nuclear regulatory approval

Following a request from the Provincial government, OPG updated the feasibility assessment for the refurbishment of Pickering Units 5 to 8, which had been scheduled for shutdown in the coming years. Subsequently, the Provincial government requested that OPG proceed with the refurbishment of these units. In response, the company sanctioned CAD2 billion in capital expenditure to advance the project. The refurbishment plan is contingent on receiving approvals from the Canadian Nuclear Safety Commission (CNSC). The company's schedule involves shutting down Units 5 to 8 in 2026, with a phased plan to return units to service by the mid 2030's. Units 1 and 4 were shutdown in Q4 2024, while Units 2 and 3 were placed in safe storage more than a decade ago.

On 23 January 2025, the Province announced its approval of OPG's plan to proceed with the project definition phase as the next step towards the refurbishment. OPG's approved budget for this work is $4.1 billion, bringing the total Board-approved budget for the project to date to $6.2 billion.

Small modular reactors entail high execution risk

Following the receipt of a license to construct on 4 April 2025, the company has started construction on the first of four 300 MW SMR's adjacent to the Darlington station, that we view as new nuclear construction entailing very high execution risk. The company expects the first unit to be in commercial operation in 2030, and will start construction on subsequent units as the first one is complete, with the remaining units in service in the mid-2030's. The gradual capacity expansion should reduce the risk of cost overruns. Each SMR will be a GE Hitachi BWRX-300 reactor and the company expects to yield benefits from a fleet approach.

The CAD20.9 billion Darlington SMR project has very high levels of execution risk as a first of a kind nuclear project. Nuclear operators have a poor track record of completing the construction of new nuclear capacity on time and budget, with cost overruns often measured in billions, and delays measured in years. We believe execution risk will be highest with the first unit, with diminishing risk on subsequent units as the company incorporates lessons learned from the construction of each unit into subsequent units. While we expect OPG to recover prudently incurred costs, we may not know whether the company will be able to recover any potential cost overruns until the Darlington SMR project is completed. We view the prospects for some form of government and regulatory support as high given the government's public request for comment.

The OEB has determined that SMR related costs may be recorded in a nuclear development variance account (NDVA). The NDVA does not have a limit but is subject to prudence review. A 13 June 2024 OEB decision approved the recovery of CAD108 million over the period 1 July 2024 through the end of 2026. These costs were associated with the non-capital preliminary planning and preparation costs that were incurred between 2020 and 2022. The company did not incorporate any SMR related spending into its 2022-2026 rate case application.

Near term financial metrics are reasonably predictable

We expect CFO pre-WC/debt to be in the range of 15-20% over the next few years with cash flow to remain reasonably predictable, although generation levels will drive some variability. These variations in generation result in a wider range in forecast financial metrics compared to transmission and distribution companies. We expect the remaining unit at Darlington to be completed ahead of schedule, providing some support to financial metrics.

There remains uncertainty over the trajectory of financial metrics as a result of the nuclear capital program. We expect that the company will be issuing a significant amount of debt to finance the capital program for the foreseeable future, putting downward pressure on financial metrics. While we think some form of government and/or regulatory support for the Darlington SMR project and Pickering refurbishment is likely, there is no clarity yet.

We expect both internally generated cash flow and debt issuances to fund the capital program, which is focused primarily on nuclear capex, sustaining capital and other smaller projects that have relatively low levels of execution risk. The company exhibits credit supportive financial policies and OPG seldom pays a dividend. However, the offset to this is that, unlike public companies, we think it could be challenging to issue equity if required, limiting OPG's financial flexibility.

Given the size of the capital program, we think that further debt financed M&A is increasingly unlikely. Management has indicated that they plan to focus on their existing assets and, given the planned nuclear projects, the company has ample organic growth opportunities.

There is some structural subordination stemming from project finance debt at Canadian contracted assets totaling about CAD2.4 billion at 31 March 2025 and about CAD516 million of debt on US assets. However, unlike the vast majority of regulated utilities, there is no debt outstanding at the key regulated businesses that generated about 69% of EBITDA in 2024. That, in conjunction with primarily centralized funding at OPG, results in no notching for structural subordination.

High probability of support from the Province provides an uplift to OPG's credit profile

Given the 100% ownership interest of the Province, OPG is considered a government related issuer (GRI) under our GRI methodology. Based on our estimate of a high probability of extraordinary support in case of financial distress, the A3 credit profile incorporates 3 notches of uplift from OPG's BCA of baa3.

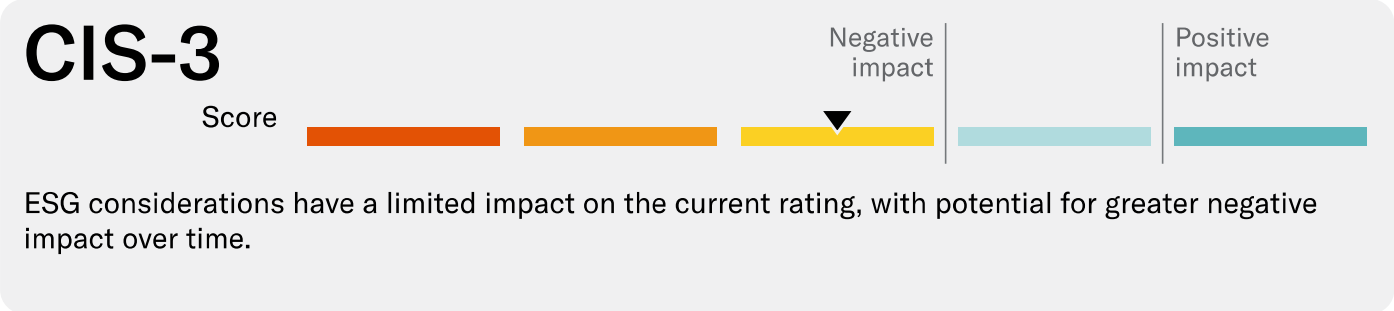
The company's ratings incorporate our expectation that extraordinary financial support to OPG would be forthcoming from the Province if needed. Our high support assumption considers that OPG produces more than half of the power in the Province at a comparatively low cost, making its infrastructure essential to the Ontario economy. OPG also implements government policy which can have negative credit implications. For example, in an effort to reduce and smooth rate increases for customers, Ontario Regulation 53/05 mandated the creation of the rate smoothing and deferral account (RSDA), including the financing of the RSDA at the long term debt rate and recovery over a 10 year period after the Darlington refurbishment is complete. The Province also appoints OPG's board, reviews and approves some aspects of its business plans and is a source of debt financing through the OEFC. We do not believe there are any barriers that would prevent the Province from providing timely support.

Our assessment of high dependence reflects that both OPG and the Province largely rely on the same revenue base and share some political risks. While the OEFC is a source of financing, OPG has been increasing the level of its borrowing from public debt capital markets.

ESG considerations

Ontario Power Generation Inc.'s ESG credit impact score is CIS-3

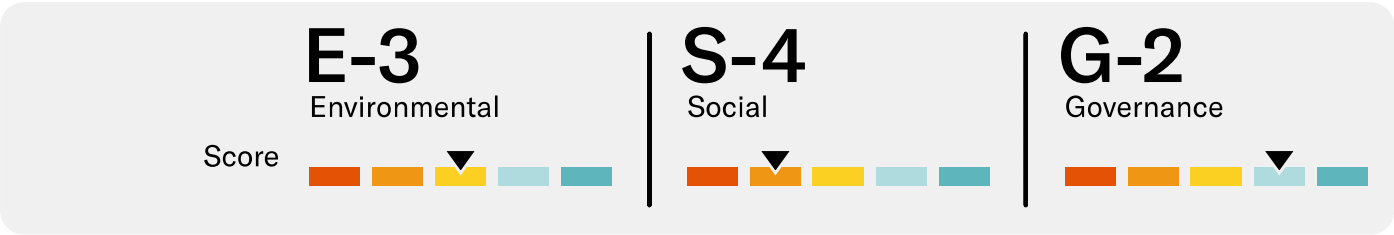
Exhibit 6
ESG credit impact score



Source: Moody's Ratings

OPG's **CIS-3** indicates that ESG considerations have a limited impact on the current credit rating with potential for greater negative impact over time as a result of physical climate risks and demographic and social trends related primarily to affordability.

Exhibit 7
ESG issuer profile scores



Source: Moody's Ratings

Environmental

OPG's **E-3** score reflects exposure to physical climate risks mostly due to extreme weather patterns which is a challenge for the sector. OPG's nuclear generation assets also have exposure to waste management and pollution risks. While the company has not had any issues with its nuclear fleet or nuclear waste, it remains an inherent risk for nuclear operators. The company has limited exposure to carbon transition risks owing to its portfolio of primarily nuclear and renewable assets.

Social

OPG's **S-4** score reflects the high risk related to demographic and societal trends associated with rate pressures as evidenced by some lengthy delays associated with recovering some costs. Factors contributing to rate pressures include more expensive sources of energy in the Province, particularly some high priced legacy renewable contracts.

Governance

OPG's **G-2** score is a function of its governance that is established by its sole owner. The company has some exposure to board structure, policies, & procedure risks resulting from its sole ownership by the Province of Ontario.

ESG Issuer Profile Scores and Credit Impact Scores for the rated entity/transaction are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for the entity/transaction on MDC and view the ESG Scores section.

Liquidity analysis

OPG has an adequate liquidity profile driven by about CAD3.6 billion of available credit facilities, unrestricted cash and expected cash flow that together are sufficient to cover its uses for the next 12 months.

As of 31 March 2025, OPG had a CAD1 billion committed credit facility that expires in May 2029 and a USD750 million 364 day revolving committed facility that expires in November 2025 with a one year term out provision at the company's option. Both of these facilities backstop CAD1 billion and USD750 million commercial paper programs that had CAD591 million commercial paper outstanding at 31 March 2025. In addition, the company has drawings of CAD211 million available on a facility from the Canada Infrastructure Bank to support SMR investments that expires in September 2027, CAD750 million undrawn on a facility with the OEFC that expires in December 2026 and CAD1,250 million undrawn on a facility with the Ontario Financing Authority that expire in December 2029.

The company has asset level facilities of CAD460 million committed at Lower Mattagami Energy Limited Partnership that expires in June 2029 and a USD20 million committed facility at OPG Eagle Creek Holdings LLC and subsidiaries that combined supported letters of credit of about CAD79 million. We have conservatively assumed that letters of credit of CAD431 million that are not allocated to above listed credit facilities are supported by corporate facilities and are reflected in our calculations of available credit facilities.

Moody's forecasts cash flow from operations over the next twelve months to be around CAD3.1 billion. In addition to the available credit facilities of CAD3.6 billion and cash and cash equivalents including restricted cash of around CAD2.6 billion as of 31 March 2025, these sources should be sufficient to cover uses comprising CAD5-6 billion of expected capital expenditures and around CAD600 million of debt maturities in the next 12 months. We expect OPG will rely in part on debt to finance its ongoing capex and refinance its upcoming debt maturities. The company's liquidity position benefits from the lack of regular dividends payable to the Province.

There are material adverse change clauses in its credit facilities that could prevent borrowings under certain circumstances, a credit and liquidity negative. Moody's expects the company to manage its program maturities, cash on hand and its swing lines in a prudent fashion.

Rating methodology and scorecard factors

The principal methodology used for this rating is the Regulated Electric and Gas Utilities rating methodology. The scorecard- indicated outcome for our 12-18 months forward view is Baa1, two notches above the BCA of baa3 with the difference attributable to elevated capex risk and OPG's generation asset base compared to all peers having at least some lower risk transmission and distribution assets.

Exhibit 8

Methodology scorecard factors

Ontario Power Generation Inc.

Regulated Electric and Gas Utilities Industry Scorecard	Current FY Dec-24		Moody's 12-18 Month Forward View	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	Baa	Baa	Baa	Baa
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Baa	Baa	Baa	Baa
b) Sufficiency of Rates and Returns	Ba	Ba	Ba	Ba
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	A	A	A	A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.4x	Aa	5x - 7x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	21.2%	Baa	15% - 20%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	21.1%	A	15% - 20%	A
d) Debt / Capitalization (3 Year Avg)	33.8%	Aa	35% - 40%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		Baa1		Baa1
HoldCo Structural Subordination Notching		0		0
a) Scorecard-Indicated Outcome		Baa1		Baa1
b) Actual Rating Assigned		A3		A3
Government-Related Issuer		**Factor**		
a) Baseline Credit Assessment		baa3		
b) Government Local Currency Rating		Aa3		
c) Default Dependence		High		
d) Support		High		
e) Actual Rating Assigned		A3		

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. Moody's forecasts are Moody's opinion and do not represent the views of the issuer.

Sources: Moody's Financial Metrics™ and Moody's Ratings forecasts

Appendix

Exhibit 9

Peer comparison

Ontario Power Generation Inc.

	Ontario Power Generation Inc. A3 Stable			NextEra Energy, Inc. Baa1 Stable		
(In $ millions)	FY Dec-23	FY Dec-24	LTM Mar-25	FY Dec-23	FY Dec-24	LTM Mar-25
Revenue	5,510	5,248	5,448	28,114	24,753	25,269
CFO Pre-W/C	1,877	1,560	1,762	11,439	12,269	12,591
Total Debt	8,729	8,625	9,711	72,206	80,599	86,694
CFO Pre-W/C + Interest / Interest	7.2x	5.6x	6.2x	4.2x	5.9x	4.2x
CFO Pre-W/C / Debt	22.0%	17.2%	17.5%	15.8%	15.2%	14.5%
CFO Pre-W/C – Dividends / Debt	21.8%	17.1%	17.4%	10.5%	9.8%	9.3%
Debt / Capitalization	33.7%	34.0%	36.2%	50.5%	51.8%	53.4%

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics™

Exhibit 10

Moody's – adjusted cash flow metrics

Ontario Power Generation Inc.

(In $ millions)	2020	2021	2022	2023	2024	LTM Mar-25
FFO	**2,538.3**	**2,231.0**	**2,471.0**	**2,590.0**	**2,024.0**	**2,276.0**
+/- Other	81.0	68.0	178.0	(57.0)	112.0	174.0
CFO Pre-WC	**2,619.3**	**2,299.0**	**2,649.0**	**2,533.0**	**2,136.0**	**2,450.0**
+/- ΔWC	103.0	59.0	223.0	(114.0)	(61.0)	(185.0)
CFO	**2,722.3**	**2,358.0**	**2,872.0**	**2,419.0**	**2,075.0**	**2,265.0**
- Div	19.0	19.0	17.0	19.0	19.0	18.0
- Capex	1,663.3	1,943.0	2,432.0	2,782.0	3,401.0	3,803.0
FCF	**1,040.0**	**396.0**	**423.0**	**(382.0)**	**(1,345.0)**	**(1,556.0)**
(CFO Pre-W/C) / Debt	17.0%	18.1%	25.2%	22.0%	17.2%	17.5%
(CFO Pre-W/C - Dividends) / Debt	16.8%	17.9%	25.0%	21.8%	17.1%	17.4%
FFO / Debt	16.4%	17.6%	23.5%	22.5%	16.3%	16.3%
RCF / Debt	16.3%	17.4%	23.3%	22.3%	16.2%	16.2%
Revenue	7,240.0	6,877.0	7,349.0	7,434.0	7,187.0	7,577.0
Interest Expense	514.0	478.6	482.0	411.6	463.9	473.4
Net Income	1,073.8	981.5	1,132.6	1,448.9	697.8	982.4
Total Assets	61,961.0	61,071.0	62,218.0	65,569.0	68,840.0	71,253.0
Total Liabilities	46,694.4	44,351.6	43,508.5	45,261.2	47,337.0	49,255.0
Total Equity	15,266.6	16,719.4	18,709.5	20,307.9	21,503.0	21,998.0

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Periods are fiscal year-end unless indicated.
Source: Moody's Financial Metrics™

Exhibit 11

Moody's – adjusted Debt reconciliation

Ontario Power Generation Inc.

(In $ millions)	2020	2021	2022	2023	2024	LTM Mar-25
As reported debt	**10.4**	**9.8**	**10.2**	**10.5**	**11.9**	**13.5**
Pensions	5.0	2.9	0.3	0.9	0.4	0.4
Operating Leases	0.0	-	-	0.1	0.1	0.1
Moody's – adjusted debt	**15.5**	**12.7**	**10.5**	**11.5**	**12.4**	**14.0**

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Periods are fiscal year-end unless indicated.
Source: Moody's Financial Metrics™

Exhibit 12

Moody's – adjusted EBITDA reconciliation

Ontario Power Generation Inc.

(In $ millions)	2020	2021	2022	2023	2024	LTM Mar-25
As reported EBITDA	3.0	2.9	3.4	3.6	2.8	3.3
Pensions	(0.2)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)
Operating Leases	0.0	-	-	-	-	-
Unusual	-	(0.1)	(0.1)	-	-	-
Moody's – adjusted EBITDA	2.9	2.7	3.0	3.4	2.6	3.0

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Periods are fiscal year-end unless indicated.
Source: Moody's Financial Metrics™

Ratings

Exhibit 13

Category	Moody's Rating
ONTARIO POWER GENERATION INC.	
Outlook	Stable
Senior Unsecured -Dom Curr	A3
Commercial Paper	P-2

Source: Moody's Ratings

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MOODY'S RATINGS

ISSUER IN-DEPTH

26 June 2025

Send Your Feedback

Ontario Power Generation Inc.

Government support for nuclear construction would be credit positive

Summary

On 8 May 2025, the Province of Ontario (Aa3 stable) announced that Ontario Power Generation Inc. (OPG, A3 stable) will proceed with the construction of four 300-megawatt (MW) small modular reactors (SMRs) on a site adjacent to OPG's Darlington nuclear generating station. The utility expects to connect the first unit to the grid in 2030. The provincial government is concluding a 45-day public comment period seeking feedback on proposed regulatory changes that would allow concurrent cost recovery for nuclear construction, as well as allow OPG to sell a portion of the Darlington SMR project to investors. Such measures would be credit positive for the utility, but their financial benefit will depend on key assumptions.

- **Very high level of execution risk associated with new nuclear projects.** Nuclear operators have a poor track record of completing the construction of new nuclear capacity on time and within budget. Delays are often measured in years and cost overruns in the billions of dollars. While we expect OPG to recover prudently incurred costs, we may not know whether the company will be able to recover any potential cost overruns until the Darlington SMR project is completed.
- **Gradual capacity expansion should reduce risk of cost overruns.** To reduce execution risk, OPG plans to build out capacity at the Darlington nuclear site by constructing unit 1 first and applying lessons learned to the construction of subsequent units. By applying lessons learned, the utility expects each unit's capacity cost to decline as the construction proceeds. Even if these cost savings fall short of the company's forecast, the gradual expansion of generating capacity should reduce the risk of cost overruns associated with the construction of large nuclear power plants.
- **Concurrent cost recovery and other forms of regulatory support would be credit positive.** Concurrent cost recovery would be credit positive because, as contemplated by the government, it would provide some cash flow during the construction phase of both the Darlington SMR and Pickering refurbishment projects. How supportive this would be for OPG's credit profile would depend on how the recovery of costs is implemented.
- **Other direct forms of government support may also be credit supportive.** Allowing OPG to sell an ownership interest in the Darlington SMR project would be credit positive because it could reduce its overall investment in the project and reduce the pressure that it would otherwise place on the balance sheet. The province and the federal government could also provide support to OPG during construction, such as through tax incentives, direct equity injections, below-market loans or loan guarantees and a funding cap, all of which we have seen in other jurisdictions.

RATINGS

Ontario Power Generation Inc.	
Senior unsecured rating	A3
Outlook	Stable

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Very high level of execution risk associated with new nuclear projects

Government support for the construction of the Darlington SMRs is important, given the substantial execution risks associated with first-of-a-kind nuclear projects. Nuclear operators have a poor track record of completing the construction of new nuclear capacity on time and within budget. Delays are often measured in years and cost overruns in the billions of dollars. Moreover, poor execution of the first Darlington SMR may erode public, political and regulatory support for subsequent units.

First-of-a-kind projects are characterized by high technology risk that can exacerbate execution risks. The GE Hitachi BWRX 300 SMR that OPG has selected is based on a 10th generation boiling water reactor technology, although it would be the first SMR project undertaken by OPG and its partners. We expect OPG to recover prudently incurred costs under the current regulatory framework. However, until the project is completed, we may not know whether the company will be able to recover cost overruns, if any. There is also the possibility of some cost sharing with contractors. But the scale of cost overruns on other first-of-a-kind projects suggest that such arrangements are unlikely to be material to OPG's credit quality.

The province's Darlington SMR announcement comes at a time when OPG also plans to refurbish existing generating units at the utility's Pickering nuclear generating station, subject to final approvals. The cost of the refurbishment and the level of regulatory support OPG will receive during construction have not been determined, heightening the uncertainty facing the utility.

Gradual capacity expansion should reduce risk of cost overruns

To reduce the execution risks associated with building the first commercially viable SMR facility in North America, OPG plans to build out capacity at the Darlington nuclear site by constructing unit 1 first and applying lessons learned to the construction of subsequent units. We expect that the construction of subsequent units will overlap, and the utility expects to apply lessons learned from each unit to subsequent units. OPG expects this "fleet approach" to the project's construction to drive down costs of subsequent units. The utility expects the first unit to deliver power to the grid in 2030 and complete all of the construction of all four units by the mid 2030s.

Common costs of $1.6 billion must be spent before the first SMR can generate power and deliver it to the grid. As shown in Exhibit 1, the government forecasts a decline in the capacity cost of each SMR as the Darlington project proceeds and expects Unit 4's capacity cost to be about a third less than that of Unit 1. There is a meaningful risk that these cost savings do not materialize, or not to the extent that the company projects.

Exhibit 1

The Ontario government expects the cost of each successive SMR at the Darlington site to decline

	Cost (CAD billions)	Capacity (MW)	Capacity cost (CAD millions per MW)*	Capacity cost ($** millions per MW)*
Unit 1	6.1	300	21.7	15.7
Unit 2	4.9	300	17.7	12.8
Unit 3	4.2	300	15.3	11.1
Unit 4	4.1	300	15.0	10.9
Unit 4 (excluding common costs)			13.7	9.9
Common costs	1.6			
Total Costs	20.9			

*Includes equal sharing of common costs
**Exchange rate of $1.00=CAD1.38
Source: Government of Ontario

Each SMR unit is considerably lower in total cost compared to larger nuclear units that are often about 1 gigawatt (GW) in size, so cost overruns on a single unit are not likely to be as large in nominal terms. OPG expects that each unit will be added to rate base and generate cash flow as completed. This compares favorably to large units, where the investment per unit is much larger, placing more pressure on the balance sheet during construction. This, in combination with what can be a long period of time to complete

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larger units, exacerbates pressure on the balance sheet from large units. However, the ability to complete construction of SMRs within a shorter time frame than that of a traditional nuclear generating unit remains unproven. Our expectation is that prudently incurred costs will be added to rate base and be recovered in rates upon the completion of the units.

In recent years, OPG has developed a strong track record as a nuclear power generator. The utility is approaching the completion of its decadelong CAD12.8 billion refurbishment of its four-unit Darlington nuclear power generating station on budget and we expect likely ahead of schedule in 2026. However OPG had the opportunity to learn from the refurbishment of Bruce Power L.P.'s (Baa2 stable) first two units about 15 years ago, and the refurbishment of those earlier units was neither on time nor on budget.

Concurrent cost recovery and other forms of regulatory support would be credit positive

The key forms of regulatory support that we expect to be considered either through the government feedback process or during OPG's next rate case include concurrent cost recovery (cash construction work in progress, or CWIP), recovery of preconstruction costs, higher equity capital and a higher return on equity.

Concurrent cost recovery would be credit positive because, as contemplated by the government, it would provide some cash flow during the construction phase of both the Darlington SMR and Pickering refurbishment projects. In addition, it would somewhat alleviate upward pressure on customer rates that would likely occur when the SMRs are brought into service because the company had been recovering its cost of capital in rates, leading to a lower rate base when the asset is ultimately placed into service.

Under the proposal being considered, OPG could recover debt interest costs associated with both projects during the construction phase. Instead of capitalizing interest expense, the company would recover those amounts in rates during the construction period when pressure on financial metrics from these projects is greatest.

How supportive this would be for OPG's credit profile would depend on how the recovery of costs is implemented. Capitalized costs are typically recovered over the life of the assets. Concurrent cost recovery that is based on forecast capital expenditures and adjusted to reflect actual spend would be more beneficial than a lagging – and likely lower – capital expenditure figure. Recovery based on a weighted average cost of capital that includes the company's interest expense and return on equity would be more beneficial. Less credit supportive would be cash flow recovered in rates that is based on a short-term or long-term debt rate (as proposed by government) that is less than the weighted average cost of capital.

Some recovery of capital investments during the construction period would also provide significant credit support to the utility. In conjunction with concurrent cost recovery, this could mimic rate base investment and these investments could put negligible pressure, if any, on financial metrics, if the investments are recovered at a level that approximates depreciation. Faster recovery of investments would be even more credit friendly. We seldom see this considered by regulators who often take the view that rate payers who benefit from a project placed in service should pay for it. This approach lends itself to cash recovery once a project is in service. However, it may also ignore the significant economic benefits incurred during the construction of the project.

OPG is already recovering some preconstruction costs in customer rates, which is credit positive. In June 2024, the Ontario Energy Board approved the recovery of CAD108 million from 1 July 2024 through the end of 2026. These costs were associated with the noncapital preliminary planning and preparation costs that were incurred between 2020 and 2022. Any recovery that the company receives before or during the construction period would be credit positive. Carrying costs on costs recovered before or during construction are lower because they are recovered sooner (instead of capitalizing an annual return on these costs until the asset is placed into service) and cash flow during construction would be credit supportive during the construction period.

Higher equity capital and a higher return on equity would likely be only modestly supportive

A higher equity thickness in the deemed capital structure only on the construction project would be modestly credit positive. While it does reduce the amount of debt on OPG's balance sheet, the company may have to provide additional equity. Also, this may lead to a higher weighted average cost of capital that, unless there is some form of CWIP, would drive project costs even higher. Higher equity capital on other, existing assets that are in service and generating cash flow would be significantly more credit positive than a higher equity layer on assets under construction that are not generating cash flow.

Similarly, a higher return on equity (ROE) on the construction project itself would have limited credit benefits unless it is combined with cash CWIP (using a weighted average cost of capital that includes ROE) or is applied to operating assets that would drive increased cash flow.

Other direct forms of government support may also be credit supportive

Allowing OPG to sell an ownership interest in the Darlington SMR project would be credit positive because it could reduce its overall investment in the project and reduce the pressure that it would otherwise place on the balance sheet. A key consideration would be the allocation of project costs and any cost overruns or delays. If project costs and any cost overruns are borne by co-owners in proportion to their ownership interest, this would be more credit positive than selling an ownership interest where OPG retains a larger share of exposure to cost overruns. Clear governance provisions among the investors would be key to understanding the credit risks under this type of arrangement.

The province could also provide support to OPG during construction, such as through tax incentives, direct equity injections, below-market loans or loan guarantees and a funding cap, similar to those found in other jurisdictions. Because we expect investments in SMRs to be added to rate base, price support mechanisms like contracts for difference or long-term power purchase agreements are not relevant to OPG.

Tax incentives that reduce taxes payable during construction and increase cash flow would be credit positive. Direct equity injections to OPG would be beneficial to the extent that they reduce the amount of debt we would otherwise expect the company to incur. Below-market loans or loan guarantees that reduce the company's interest expense and increase its cash flow would also be supportive, although we would likely consolidate the debt. A funding cap that shifts cost overruns beyond a predefined point from OPG to government would alleviate risk. Finally, long-term regulatory and policy certainty, which we believe OPG has, that addresses the potential for long-term shifts away from nuclear power generation would mitigate this risk.

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REPORT NUMBER 1453076

S&P Global
Ratings

Research

Tear Sheet:

Ontario Power Generation Inc. License To Build Small Modular Reactor Is Credit Neutral

April 14, 2025

This report does not constitute a rating action.

What's new: The Canadian Nuclear Safety Commission recently issued Ontario Power Generation Inc. (OPG) a license to build the country's first small modular reactor (SMR). OPG intends to build a GE-Hitachi Nuclear Energy Inc. BWRX-300 reactor at the Darlington nuclear plant site in Clarington, Ontario. The license is valid until March 31, 2035. OPG plans to install four BWRX-300 SMRs at the site. The BWRX-300 is a boiling water reactor design that uses natural circulation for cooling. However, the decision does not authorize the operation of a BWRX-300 at the site. That would be subject to a future commission licensing hearing and decision.

Why it matters: This is a key milestone for the project as it shows continued confidence from the Canadian nuclear regulator in OPG to execute this project. The next step is for the Province of Ontario to approve the company to commence nuclear construction. We generally view the building of SMRs as negative for credit quality since it entails potential construction risk due to its first-of-its-kind technology. Developing new nuclear power plants is a highly complex project characterized by extensive timelines, significant capital investments, and inherent execution risks that can lead to significant cost overruns and delays. However, the Canada Infrastructure Bank provided a $970 million commitment to fund the project. Additionally, we expect the company to benefit from direct or indirect federal government incentives including applicable clean energy investment tax credits to partially fund these investments.

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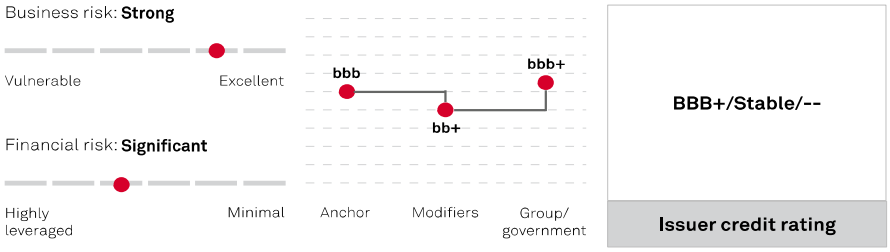
Ratings Score Snapshot



Recent Research

- Full Analysis: Ontario Power Generation Inc. , Aug. 14, 2024

Company Description

OPG is an Ontario-based electricity generation company. The company's generation fleet comprises about 18,225 megawatts (MW) of capacity. OPG is wholly owned by the Province of Ontario.

Outlook

The stable outlook on OPG incorporates the following expectations: more stable cash flows, no significant acquisitions, effective management of its regulatory risk, and that OPG will complete its future nuclear investments including refurbishments and small modular reactors on time and on budget. We also forecast funds from operations (FFO) to debt of 14%-16%.

Downside scenario

We could lower our ratings on OPG within the next 12-18 months if its financial measures weaken, including FFO to debt consistently below 13%. This could occur if the company experiences delays and cost overruns in its Darlington refurbishment program, faces adverse regulatory decisions, or undertakes significant debt-funded acquisitions. Alternatively, we could lower our rating if we downgrade the Province of Ontario or the relationship between OPG and the province unexpectedly deteriorates.

Upside scenario

Although highly unlikely, we could raise our ratings on OPG within the next 24 months if there is no change to its relationship with the Province of Ontario, it doesn't expand its nonutility businesses through acquisitions, and it materially improves its financial measures, including FFO to debt consistently more than 20%.

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Rating Component Scores	
Foreign currency issuer credit rating	**BBB+/Stable/--**
Local currency issuer credit rating	**BBB+/Stable/--**
Business risk	**Strong**
Country risk	Very Low
Industry risk	Low
Competitive position	Strong
Financial risk	**Significant**
Cash flow/leverage	Significant
Anchor	**bbb**
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Negative (-1 notch)
Liquidity	Adequate (no impact)
Management and governance	Neutral (no impact)
Comparable rating analysis	Negative (-1 notch)
Stand-alone credit profile	**bb+**

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, April 4, 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013

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	NN-New Nuclear Operational Phase Risks	FOAK
63708	**Risk Based Maintenance Strategy Not Implemented to Support Staffing Model May Lead to Schedule Delays and Rework.** EVENT: The maintenance strategy may not ensure equipment reliability is maximized and OM&A costs are minimized (materials, contract costs and head count). CAUSE: 1) Maintenance strategy is not developed in a timely manner. As a result, support functions such as supply chain and digital strategy do not have sufficient time to develop their program to meet the project needs. 2) Condition based maintenance not implemented 3) Strategy to replace vs repair not optimized. 4) Maintenance contracts not appropriately used 5) Processes do not facilitate a graded approach when planning for, obtaining parts for and performing maintenance on non-safety related equipment 6) Insufficient availability of contractors to fill both ongoing (online and outage) and emergent (unplanned failure) needs. This includes both maintenance, Inspection and RP staff. 7) work management and scheduling strategy not set up to allow success of the maintenance strategy (digital aspect, AI etc) 8) Supply chain strategy not set up to allow success of the maintenance strategy (parts ID, warehousing & issuance, ordering, procurement, vendor of record, emergent repairs). IMPACT: Increase to OM&A costs as a result of: 1) Outage extensions (MW) 2) Poor equipment reliability and/or Forced outages (MW) 3) More work being done than required (people, parts, time) (Staffing) 4) Ineffective processes (Staffing) Project Schedule delay and/or rework as a result of: 1) Maintenance requirements not specified to meet other project deliverable timelines (i.e. digital strategy) 2) Work management not ready for equipment turn over	yes
61443	**The DNNP Station Administrative Program may not be developed to support the Commercial Operation Staffing Model, leading to an increase in staff for On-line and Outage work, engineering and supply chain.** EVENT: Updates to the DNNP Station Administrative Programs may not be yield the assumed efficiencies. CAUSE: potential causes include: (1) failure to establish simple, innovative, digital solutions for parts procurement, receipt and dispatch. (2) failure to optimize plant online parameter monitoring - specifically. Failure of the digital strategy to gather plant performance data and failure of the M&D center to process the data for condition/predictive maintenance and real time status monitoring. (3) failure to implement a managed system with limited administrative burden (4) failure to establish a process to allow simple outages planning (5) the process to generate a "ready" work package is not simple (6) the process to schedule work is not simple (7) -- IMPACT: (1) increase in supply chain workers of 8 people = $15004 k (2) increase in engineering staff of 8 people = $1 500 (3) increase in staff to support compliance and administration - 22 people = $4 100k (4) increase in outage scheduling staff of 9 people = $1800k (5) increase in staff to plan and assess work -10 assessor = $1500k (6) increase in staff to schedule on line work - 5 on line planners = $1 000k (7) --	yes
	Potential increase in SMR Management System development due to external audit and assessments. EVENT: SMR Management system Development may be adversely impacted by external audit and assessments that recommend growth in the requirements	

	NN-New Nuclear Operational Phase Risks	FOAK
64277	CAUSE: 1) Auditor may not use or agree with OPG's risk based approach 2) Base OPG may support audit findings as they do not understand SMR risk profile and need to operate as a comparable business to other forms of power generation 3) Existing measures and requirements from external auditors (WANO, NSRB, Safety Culture, IAEA etc.) are not geared towards SMRs with their lower risk profile IMPACT: Growth in SMR MS requirements will result in additional resources required to implement the expectations of the system. It may also result in significant rework and use of resources in the later phases on the project to support additional document development.	yes
64322	**Fire response programs that are not adequately designed may lead to additional safety risks and resource costs for equipment and training** EVENT: The requirements for operational DNNP fire response is resource intensive And the requirement for fire system testing is resource intensive CAUSE: 1> Design of the plant does not allow the most limiting fire to go unmitigated to allow time for off site response 2> Post fire response of the control room and field techs is too high to allow them to support the reactor safety / plant response and the fire response. 3> the program for the new operational response is not ready in time to support the major update to the program 4>Design is such that reduction in fire areas and significant Screen levels (reduced Screen 2 and Screen 3) have not been realized. 5> municipal fire collaboration agreements cannot be reached 6> failure to minimize the amount of resource intensive fire system testing 7> failure to implement software solutions to track administrative requirements of the fire program IMPACT: for fire response - assume 6 people per crew and 5 crews = 30 total people dedicated to fire at all time. with an approximate burden rate of $200k per person per year this is an extra $6 million per year. For testing strategy - assume 2 dedicate maintainers for fire testing. 2x burden rate of $200 = $400k per year 1 person on days to administer the fire program	yes
63923	**Implementation of a multi-skilled worker may not be effective.** EVENT: Implementation of a multi-skilled worked may not be effective. CAUSE: FT multiskilled workers – unable to find people that have the skill set to perform a range of tasks. FT - all of operations, maintenance, RP, Chem tasks, fire escort, rescue Security – security and operational tasks (fire checks and activities) Maintenance – maintenance, operational, rescue, RP Training – training, maintain & perform base position, procedures Unable to find people with the right mindset to drive issue resolution, problem solving and continuous improvement. Attraction and retention issues. Workers may be attracted to other OPG plants where they have less responsibilities. Initial and continuing training duration not practical. Union issues (i.e. grievances) may prevent implementation IMPACT: Increase in OM&A costs as a result of: 1. Increase need for staff 2. Low quality work 3. Inefficient processes/rework 4. Gaps in operational programs leading to poor performance	yes
6	**DNNP RP Protection Model and Associated base qualifications may not be optimized to support the staffing model, resulting in 3 additional FTEs for the life of the station.** EVENT: DNNP staff (site and contract) may incur a safety risk when performing RP work. CAUSE: potential causes include: 1) Failure to train site staff to provide the in-scope RP protection for normal DNNP RP hazards	

	NN-New Nuclear Operational Phase Risks	FOAK
61065	1) Failure to train site staff to provide their own RP protection for normal DNNP RP hazards. 2) failure to provide a RP protection solution for contract staff during online work 3) failure to provide a RP protection solution for contract staff for outage work IMPACT: The consequence is an Increase in the need for specialty RP technicians and health physics people to support station work activities. This would require an additional 2 RP and 1 HP person to support online work.	yes
64572	**The complexity associated with developing computer-based procedures may be a risk to implementation.** EVENT: The complexity (timing and resources) of procedures development and implementation is not well understood CAUSE: 1. Updates to procedures is complex/lengthy and requires specific training and expertise. 2. a detailed schedule is not available to identify all required tasks, logic tied and milestones. 3. to meet reliability requirements, paper based back ups may be required. 4. the scope of work that OPG is responsible for (preparation of procedures, review & approval of procedures) is not well understood. This includes delineation of procedures provided by the design team vs the procedures to be created by the operations and Maintenance organization. 5. procedures cyber security requirements are restrictive and may incur additional costs. 6. CBP licenses and compatibility requirements are not in place in time to start training. 7. OPG does not have the right level of expertise to review procedures given our CANDU background. 8. process to commission is not known 9. CBP is not in place in time for system turnover IMPACT: potential impacts of standing down CBPs and going to full paper: 1) increase in resources to support preparing, updating and maintaining procedures during both the project and OM&A phase - assume 3 dedicated people (1 ops, 1 Maint, 1 admin) at a burdened cost of $200 per year = $600 per year. 2) increased costs maintain paper = cost of admin staff to maintain paper and paper overhead (paper, photocopiers etc) = $200 k per year. 3) increase in resources due to losses as a result of CBP efficiencies (i.e. links to WOs, CRs, drawings, etc) - assume 30% increase in head count = 6 FTs = 2 MM = 2 CM = 3 ANOs = 1 chem tech assume $200k per person, 16 people = $3.2 million a year impact of delay of training - paper based procedures. OM&A costs per above estimate in item 3. Impact of poor quality procedures: potentional delay to project - 1 month to fix	yes
61064	**Specialized Radiological Protection Tasks may not be optimized to support the staffing model, resulting in two additional FTEs for the life of the station.** EVENT: specialized RP tasks (i.e. class 7 rad shipments, Non-Routine Surveys etc) may have an increased radiological risk when executed. CAUSE: Causes include: 1) Inability to coordinate specialized RP activities while the qualified people are available 2) Inability to cross train (non-RP) plant site staff to perform these tasks proficiently IMPACT: The consequence is the increase in RP staff – 2 extra techs, over the life of the plant, 60 years.	yes
	Inefficient DNNP Station Design may Cause an Increase in Staff EVENT: BWRX-300 DNNP plant design goal of minimizing the reliance on people to support plant operations, maintenance and accident response may not be achieved. CAUSE: potential causes of this include:	

	NN-New Nuclear Operational Phase Risks	FOAK
61441	(1) More Resources (Actual vs Planned) are required for post accident mitigation (2) Failure to provide remotely displayed radiological conditions for accessible area (3) failure to instrument and analyze plant equipment and systems to allow efficient data gathering trending and actions. (4) Inability of the station design to minimize security vulnerabilities and/or implement non-personnel mitigation (i.e. passive systems, alarms, cameras etc) to the acceptance of the CNSC where identified. (5) application of safety classification to non-safety class SSCs IMPACT: impact is the increase in station staff and O&M cost following commercial operation. This cost is estimated per the following: (1) increase in min complement staff. It is assumed the minimum complement will be closer to a full scale BWR plant - which is 1 shift manager, 1 CRSS, 2 ANOs, 3 field staff. this represents an additional 1 supervisor, 1 ANO and 1 FT. Assume ~ $1million in salary for these 3 workers per year per crew. For 5 crews = 15 people = $5 million dollars a year. and for 4 units with 5 crew = 60 people and $20 million dollars a year. (2) need for an increase in RP staff = 5 RP techs = $ 750k (3) need for more 8 additional engineers and 5 field techs = $1 500 + $1 000 = $2 500 (4) need for additional security resources = $3 250	yes
61789	**Early Operation of DNNP May be Impacted by Fuel Defects due to Poor FME Control that May Cause Increased Contamination and Dose Rates and Removal of Unspent Fuel** EVENT: Early operation of DNNP plant may see a high number of fuel defects CAUSE: potential causes of this condition include: 1) Poor FME control during construction 2) Lack of controls/processes in place to ensure all systems interfacing the fuel are FME free prior fuel load. 3) Lack of controls/process in place to ensure all systems interfacing the fuel are FME free during operations and maintenance 4) FME on the fuel following manufacturing and prior to installation (i.e. post manufacturing, during transport and receipt of fuel at site, up to staging in the fuel pool). 5) Poor system chemistry and chemical/material controls IMPACT: impacts include: - environmental releases - increased contamination in the coolant and resulting increase dose rates and dose. - financial impact due to need to remove unspent fuel, need to reanalyze the core, and need to shutdown to refuel	No
68258	**There is a risk that AECON, performing the construction activities, may not adequately document Load Verification in accordance with OPG's requirements.** EVENT: Construction activities require installation of electrical and air supplies to various loads. Electrical and air supplies must be verified, and verification must be recorded to ensure work protection activities during commissioning and during operation can be conducted without the need for rework. AECON, performing the construction activities, may not be aware of OPG's specific requirements for data collection and verification of electrical/air supplies to various loads leading to rework during operation and delays to work protection application. CAUSE: AECON is performing construction and may not be aware of OPGs requirements and what data must be collected. IMPACT: Delay to commissioning due to the need to repeat load verification. Increased operational cost to redo LV for station once facility is turned over to OPG.	No
61066	**Inadequate Plant Design May Lead to Mobile Platforms Required to Access Equipment (On-line & Outage), Increasing Lifecycle Costs** EVENT: Access to some equipment for operation and maintenance requires erecting of a scaffold. CAUSE: Failure to design the plant such that all equipment is accessible with either permanent or mobile platforms. IMPACT: Additionally, 4 civil maintainers and a civil design engineer would be required. Additional costs associated with Scaffold Erection, Scaffold Inspection, Scaffold User training and the capital cost of maintaining scaffolding material inventory. These extra costs are required over the life of the plant, 60 years. Alternatively a cost associated with contracting out scaffold construction would be incurred.	No

	NN-New Nuclear Operational Phase Risks	FOAK
61756	**Insufficient Space for Material/Equipment Storage and Personnel Use May Lead to Delays in Online/outage Work and Critical Path Activities.** EVENT: There will be limited storage space for equipment/maintenance and space for people (PJB areas, eating areas, break areas, office areas) at the BWRX-300s during routine operations and outages. CAUSE: The BWRX-300 Small Modular Reactors are intentionally being designed to be smaller than current reactor designs. IMPACT: There may not be adequate storage space for tools, equipment, and materials that are necessary for the operations and maintenance of the plant. There may not be adequate space for people to use as PJB areas, eating areas, break areas, and office areas when supplemental staff are on site for outages or maintenance projects. This could lead to work process inefficiencies and delays to online/outage work including critical path activities.	No
64039	**Ineffective Outage Planning and Execution Strategy May Lead to Extended Outages, Increased Operations and Maintenance Costs and Inefficient Staff Utilization.** EVENT: The outage strategy may not ensure equipment reliability is maximized and OM&A costs are minimized (outage duration, materials, contract cost and head count). CAUSE: 1) Worker Logistics – security processing, office space, shops, change rooms & lunch rooms within PA - is not set up to minimize delays 2) Worker Logistics (Processing) – security, RP, onboarding etc is not set up to minimize delays 3) Station staff during an outage not well utilized (i.e. engineering support, OCC, maintenance coordinators etc) 4) Maintenance contract strategy not appropriately understood and implemented. 5) Insufficient availability of contractors to fill both ongoing (online and outage) and emergent (unplanned failure) needs. This includes both maintenance, Inspection and RP staff. 6) The compact layout of the plant does not provide sufficient space for the laydown of equipment, tools and material required to support maintenance. 7) OPG's Lack of experience with BWR outages may result in blind spots 8) fuelling with the depth of water may be difficult IMPACT: No impact to project. Impact to Station is an increase to OM&A costs as a result of: 1) Outage extensions 2) Ineffective use of staff (station staff and contracts)	Yes
69824	**Gaps in operations experiential knowledge leading to issues or events during the project phase (i.e. training & procedure development and commissioning)** EVENT: OPG operates CANDUs and therefore has CANDU operational experience. The OPG operations team does not have working knowledge or experience with BWRs. Although several aspects of CANDU and BWR operation are similar or the same, there are a number of areas that are very different and so OPG does has not accumulated operating experience in these areas. CAUSE: Selection of a BWR technology for SMRs IMPACT: Gaps in operations experiential knowledge leading to issues or events during the project phase (i.e. training & procedure development and commissioning) and operational phase (performing procedures and tasks).	No
69782	**F15 Outage Equipment requirements not accurately defined resulting in requirement to purchase additional equipment.** EVENT: Currently the In vessel inspection platform purchase is not defined as being required. Replacement cost (Capital Expenditure) not included in cost estimate. GeH has indicated that the in vessel inspection platform may not be required and as such the replacement cost for this equipment has not been included in the cost estimate. Potential for GeH to provide as part of a Refuel Inspection Service Contract. If required and not included in Service Contract, additonal $ 2 million US cost will be incurred. GeH indicating if required this equipment can be shared between DNNP1-4 and would be a one time additional cost for the site. CAUSE: Inspection requirements not accurately defined at this stage in desgin to account for requirement for in vessel inspection platform. IMPACT: Additional capital expenditure not captured in the cost estimate of approximately $2 million USD.	No
61	**Improper Use of Service Contracts May Cause DNNP Staff to Perform Specialty Maintenance in House Which Would Increase Project Costs and Induce Schedule Delays** EVENT: DNNP is Challenged to perform specialty maintenance in house. CAUSE: Potential causes include:	

	NN-New Nuclear Operational Phase Risks	FOAK
078	1) Failure to establish contracts for maintenance on specialty equipment (i.e. chemistry instruments, rad instruments, complex or rarely serviced equipment) through use of Vendor of Record Contracts or Master Service Agreements. 2) insufficient qualified contract administration staff in place. IMPACT: The consequence is an increase the resources required for specialty maintenance crews, training and procurement and warehousing of specialty parts.	No
61061	**Work Management Automation - Insufficient Automation of DNNP Work Order Package Preparation and Scheduling May Result in the Need for a Maintenance and Ops Assessing Team** EVENT: On line and outage DNNP work order tasks, may not be fully assembled prior to job execution - Work management and scheduling strategy not set up to allow success of the maintenance strategy (digital aspect, AI etc.) CAUSE: Potential causes include: 1) Automation tools not fully implemented to support the automatic creation of DNNP WO Packages and Scheduling 2) Failure to develop a simple process for the execution crew to assemble unexpected work orders (*i.e. AI) and update task instructions based on their OPEX IMPACT: The consequence will be the need to create a maintenance and ops assessing team to assess the tasks, link procedures, prepare work protection and ensure the right parts are linked – 10 assessors for the life of the plant, 60 years.	Yes
64114	**DNNP Chemistry program may require additional operating costs if automation is not sufficient and increased routine sampling is required** EVENT: The program to support DNNP may be resource intensive to run. CAUSE: 1) Sampling requirements total and frequency is high. - actions: 63246, 63249, 63250, 63251 2) Manual sampling and analysis is complex (not allowing Field techs to perform) - actions: 63257, 63260, 63261 3) Design is not optimized - actions: 63262, 63263 4) The program is modelled after large scale nuclear which may have some inefficiencies - action 63264 5) The program is not established with an optimizing resources as a goal - actions: 63265, 63266, 63268 6) Automation is not utilized- action: 63269 7) Equipment is not reliably available to perform “automatic” functions - action 63251 8) Lack of capability/Proficiency in non chem staff to perform chem tasks effectively actions: 63271, 63273 9) Administrative burden is high (training, reports etc) - action: 63275 10) Scope of Chemistry is broader than just chemistry activities (i.e. RP, environmental sampling/analysis & reporting) - actions: 63276, 63277 11) Transient conditions (out of spec) and specific evolutions (i.e. startup, shut down) require a higher sampling & analysis frequency - actions: 63278 IMPACT: Increase in operational costs increase in staffing - assume 2 Chem techs per crew per shift - total of 10 additional- chem techs. = $2 000k per year	No
	Design of System Operation Outside of the Protected Area may Result in the Need of Five Additional Field Techs EVENT: DNNP minimum complement constraints may restrict necessary operation of equipment outside of the Protected Area (investigate equipment alarms/failures, consumables receipt (Gases) etc). CAUSE: solutions to support monitoring, operation and testing of station equipment outside of the PA are not used. this includes the following: - Technology solutions (i.e. camera for remote monitoring)	

	NN-New Nuclear Operational Phase Risks	FOAK
61095	- Technology solutions (i.e. camera for remote monitoring) - Remote controls and indications of equipment outside the PA - Service agreements with vendors to re-fill consumable tanks - coordination of planned activities outside the PA on days shifts strategies are not employed to allow people to leave the PA and still remain credited to perform their min comp role. IMPACT: Increase in staffing of 5 additional field techs (1 per crew) to ensure min comp is met when people are dispatched outside the PA. assuming the burden rate of ~$200k per FT, this represents ~$100-k per year or $60 million total for the 60 year life of the plant. *Note 1- this risk MAY be addressed/covered by the planned increase in staff planned to commission U1. that is, there will be additional available staff at site to overstaff the back shifts and allow people to leave the PA. *Note 2 - once Unit 2 is staffed with qualified people, this is no longer a concern. The number of staffed FTs will go from 3 FTs to	No
69465	**There is a risk that moving the chemistry lab to the west of the control building may not provide environment to ensure stability of analysis processes due to being in a modular structure with an entrance to the outside** EVENT: Chemistry lab environment must be temperature and humidity controlled, must be clean from outside contaminants (ex. salt in the winter), must not allow pressure differences to cause wind to enter through doors and must have a breaker to switch power buses for outages and/or maintenance CAUSE: Placement of HVAC components, insulation of modular building, entrance from outdoors, and backup power not considered IMPACT: This could cause delays in sample analysis results. Depending on the situation, samples may need to be shipped off site.	No
63919	**Risk of SMR Digital Operations do not facilitate OM&A during the project and commercial operations; due to Managed Systems not defined in a timely manner or requirements by stakeholders to deploy all the compatible tools; resulting in loss efficiencies.** EVENT: The SMR Digital Operations does not facilitate OM&A during the project and commercial operations. CAUSE: The following causes can be associated/linked in part to the new Nuclear Management System not being defined in time to select the tools that will support the Operations requirements. 1) Individual work groups are crediting the digital strategy for realizing efficiencies, but they are not within the scope of the digital strategy 2) Software not within the scope of digital strategy may not be compatible with the existing digital strategy/ tools. 3) Standard plant design is not progressing at the rate needed to support OPGs digital strategy time line 4) SMR Digital operations tools (including Enterprise assessment System (EAM), specific tools) may not be in place to support early project activities (i.e. commissioning outputs, work management pre-planning, training). Potential causes included late selection of tools, inappropriate tools, etc.) 5) Digital strategy solutions are either not user friendly, or people are not adequately trained. IMPACT: Increase in O&M costs as a result of increased staffing requirements Increase in project costs as a result of schedule delays and rework. Increase in project costs as a result of required software to realize efficiencies that are not currently within the digital strategy scope.	Yes



DNNP Overview

- Project and Operations

October 15, 2025

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SMR Units

OPG is **advancing planning, licensing and construction** for four SMRs at the Darlington site.

Four units would produce a total **1,200 MW**, equivalent to **powering 1.2 million homes.**

The four SMRs are expected to increase Canada's GDP by **$38.5 billion** over 65 years.

Over the next 65 years, OPG's SMR fleet is expected to sustain, on average, about **3,700 jobs** per year, including **18,000 jobs** per year during construction.

About **80% of project spending** will go to companies across Ontario and construction of the SMR fleet is expected to drive **$500 million** annually into the province's supply chain.

In March 2025, the Ministry of Environment and Climate Change announced **$55 million** to support the development of these SMRs.

Multiple units will allow common infrastructure to be shared across units, further **reducing cost.**

BIG THINGS START SMALL.



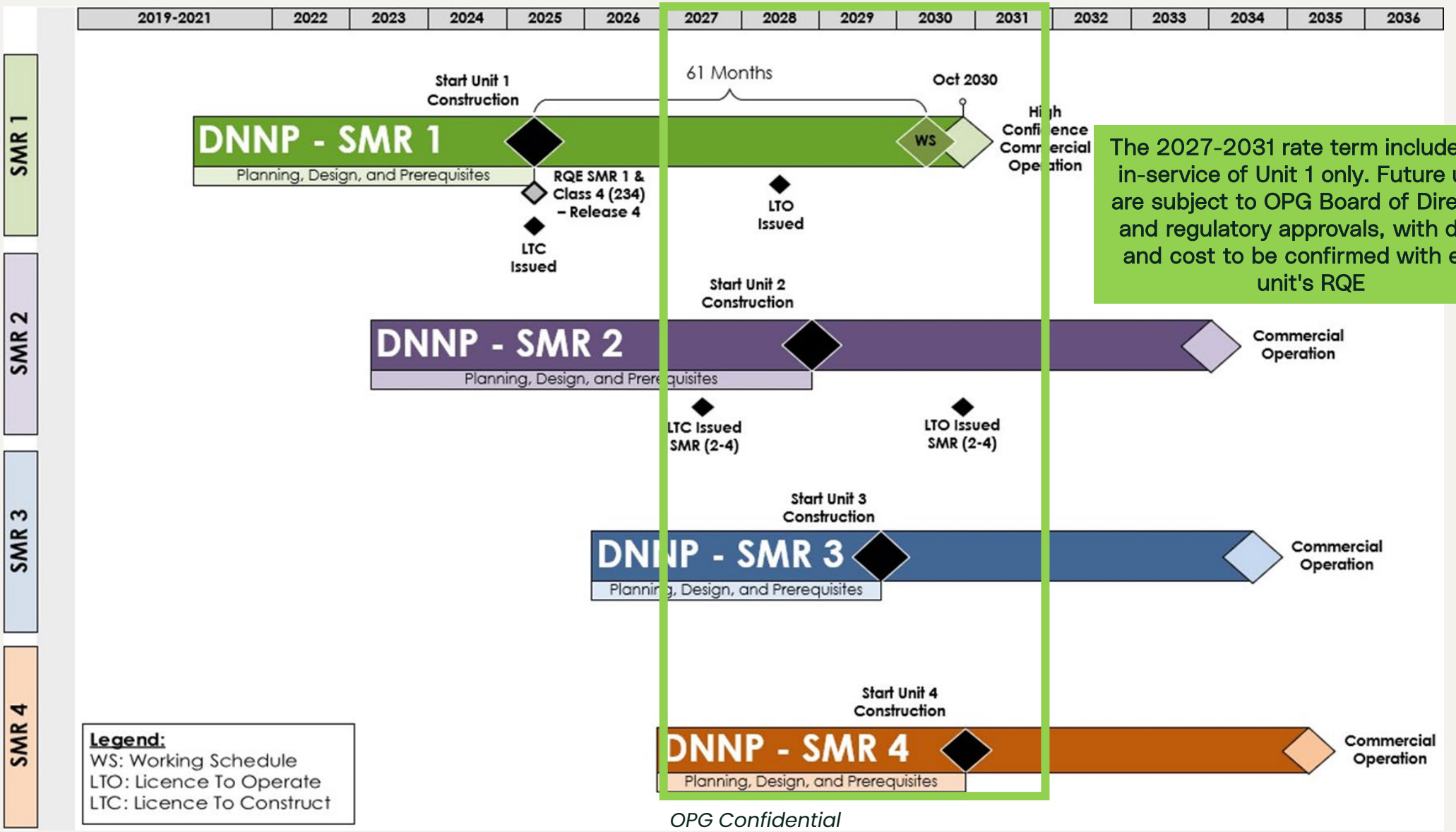
Units 2-4 construction is subject to OPG Board of Directors and regulatory approvals

Darlington New Nuclear Roadmap

BIG things start **small**.



Darlington New Nuclear 4 Unit Program Schedule



The 2027-2031 rate term includes the in-service of Unit 1 only. Future units are subject to OPG Board of Directors and regulatory approvals, with dates and cost to be confirmed with each unit's RQE

OPG Confidential

Darlington New Nuclear Project

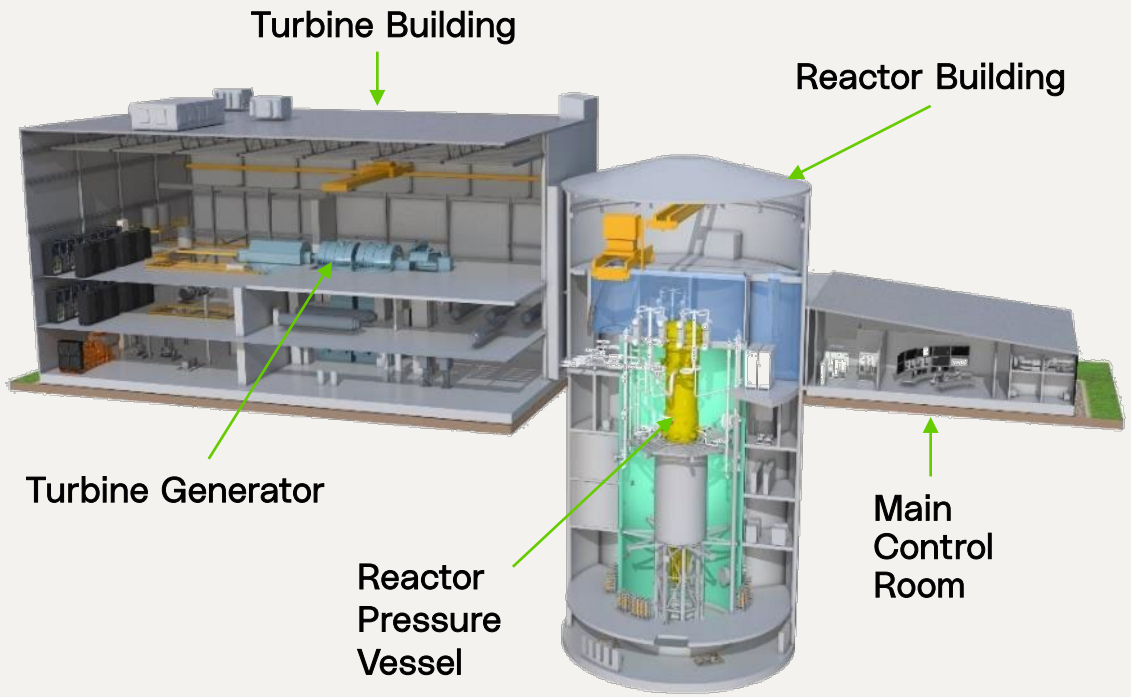
- The total cost of the four-unit DNNP, including interest, cost escalation, and contingency, is currently estimated at approximately **$20.9 billion**, of which the approved budget is **$7.7 billion** for the first SMR (**$6.1 billion**) and systems and services common to all four SMRs planned as part of the project **($1.6 billion**).

- OPG and its project partners will continue to refine the total estimated project cost during the definition phase of the remaining three units, incorporating lessons learned from the construction of the first SMR and the Darlington Refurbishment project. OPG plans to submit the application for the License to Construct Units 2-4 in Q3 2026, with targeted issuance in Q2 2028.

- In May 2025, the Province of Ontario proposed potential changes in regulations that would establish a new mechanism for concurrent cost recovery to allow OPG to recover debt interest during the construction period of the DNNP (and the Pickering Refurbishment project, if approved to proceed). OPG continues to explore optimal financing arrangements in support of funding requirements for the planned capital investments.

Technology Overview

GE Hitachi: *BWRX-300*

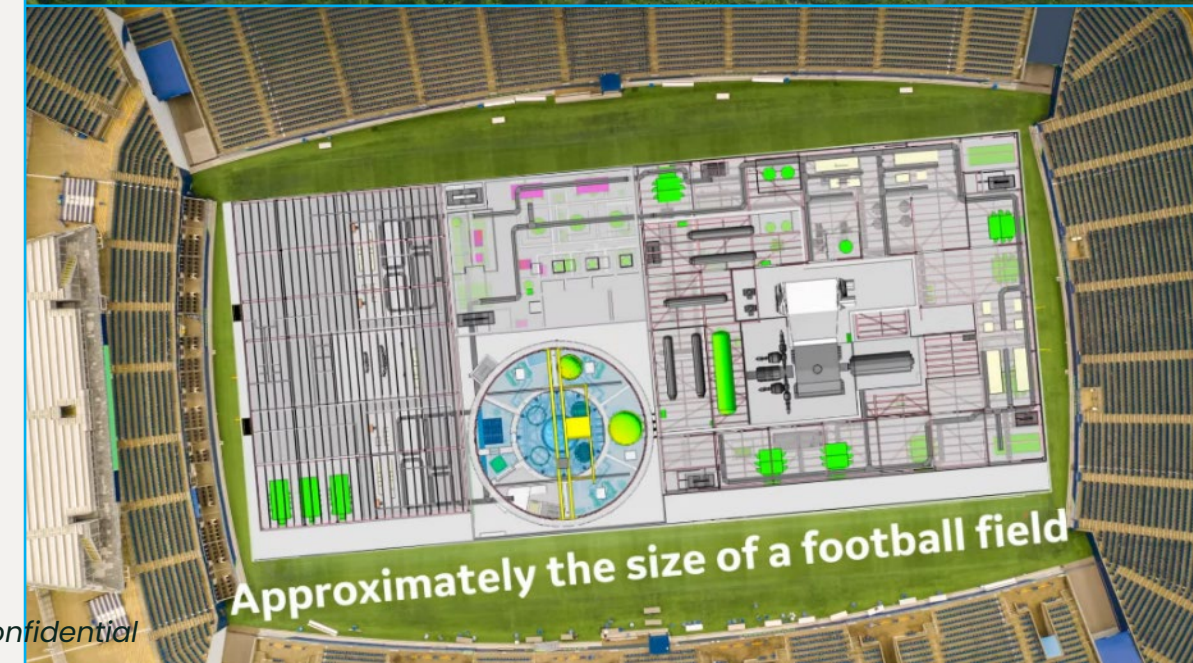


GEH SMR Technologies Canada is the Canadian division of the world-leading provider of reactor technology and nuclear services.

Designed for a 60-year operational life

~300 megawatts, which is enough to power 300,000 homes

Boiling water reactor using natural circulation



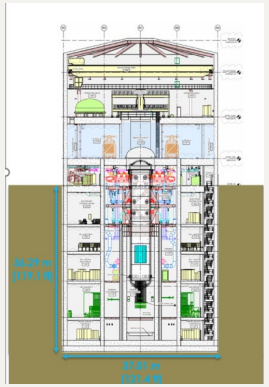
Scope Overview | Unit 1 & Common

1 Common (4 Units)



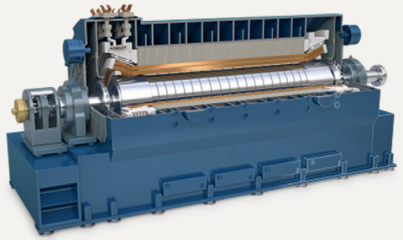
Tunnels, Intake Outfall, Shoreline Protection, Pumphouse, Security Building, Admin Building, Warehouse, Fabrication Building, Engineering Design

2 Nuclear Island



Reactor Building, Control Building, Radwaste Building, Nuclear Systems, Instrumentation and Control systems

3 Conventional Island



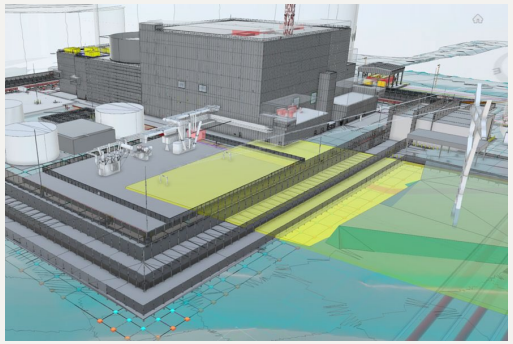
Turbine Building, Turbine, Condenser & Auxiliaries, Electrical System and Security

4 Balance of Plant



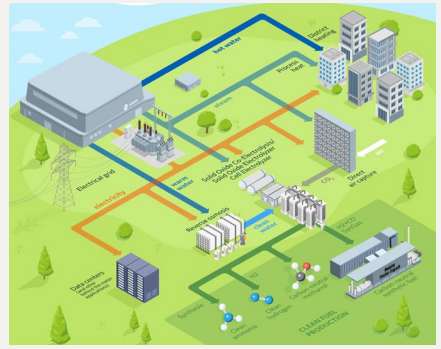
Site Establishment, Excavation, Power Block Yard, Utilities

5 Site Specific Design



Site Specific Design

6 Functional



OPG PMT, Non-IPD Projects

OPG Confidential

Integrated Project Delivery Model

Darlington New Nuclear Project – Non-Owner Partners

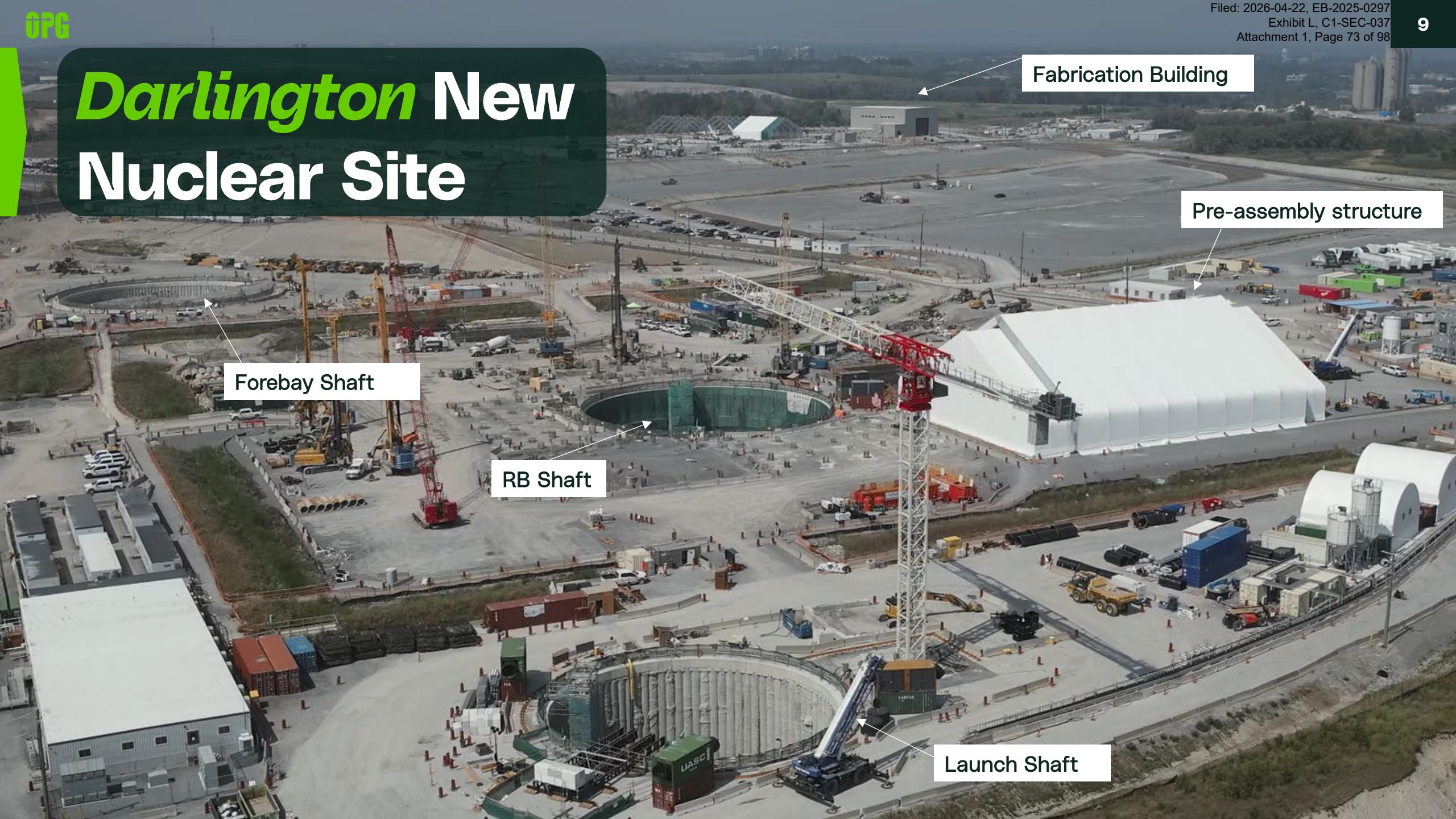
Owner* and Licence Holder	Architect Engineer	Technology Developer	Constructor
Ontario Power Generation	AtkinsRéalis	GE Vernova Hitachi	Aecon Kiewit Nuclear Partners

Why the Integrated Project Delivery (IPD) model?

- One team approach was a success on Darlington Refurbishment project
- Integrates people, systems, business structures and practices
- Joint management and collaborative decision making to achieve goals
- Unique cost and profit structures to promote teamwork

*Until transferred to DNNP SPV

Darlington New Nuclear Site

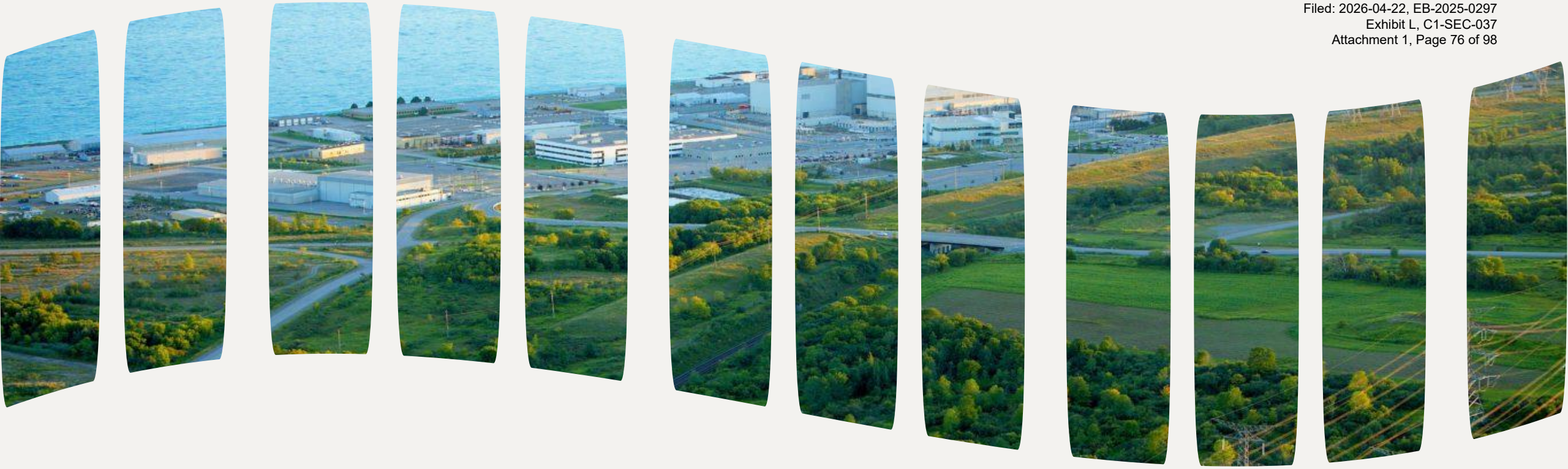


Unit 1 Planning Assumptions for 2030/31

	Assumptions	Details
SMR	Commercial Operation Date	Unit 1 – 17 OCT 2030
	Forced Loss Rate (FLR)	12%/6%/4% (Years 1, 2, 3) Steady state: 2%
	Reliability Outage	15 days (within 6 months after COD) to address any warranty issues
	Planned Outages	After first year, 50-day outage for refueling, standard inspection and maintenance, address any other issues
	Generation Plan	2030: 0.5 TWh 2031: 1.8 TWh

Program Risks – Unit 1 Commercial Operations

	Description	Mitigation
Operational	**Outage** – FOAK outage uncertainty for: - Duration: scope and duration of work - Resource: equipment, parts, contracts **Procedures and Processes** – Scope, detail and interface with other procedures and processes **Digital Technology impact on Resources** – implementation of automation to support lower head count	Outage - Generation Planning Methodology Processes – Early development and regulatory engagement. Use of industry OPEX and challenges. Tech – Early stand-up and focus on data quality
Ongoing Project Execution (Units 2-4)	Construction: • Proximity of unit 2-4 to unit 1 and shared services Design and Operations • Tie-in work that could impact unit 1 production – FOAK discharge structure, common switchyards, and shared SSCs	Construction: • OPG will have operational control of U1 and project oversight to plan around the impacts. Constructor is aware of the tight construction place and planning. Impacts would be for errors and/or extended durations of installation Design and Operations: • Designs will be simulated and demonstrated through modeling. Risk would be to the MW output. • OPG will have operational control
Licensing	CNSC may impose operational restrictions and/or hold points leading to lower output, added outages/inspections, changes based upon FOAK nature and/or issues found during commissioning/operations	Early regulatory engagement and planning through established protocols
Supply Chain	New supply chain: suppliers, parts, fuel processing Unplanned component failures on high lead time items	Fuel is standard GNF-2 BWR fuel. Uranium will be sourced from Canada, existing supply contracts leverage US based suppliers for enrichment, conversions, and fabrication; however, we have alternate international suppliers available for all steps of the process. Proactively identify off the shelf components where possible, and leveraging known supply chain



DNNP Overview

– SPV and Regulatory Structure

October 10, 2025

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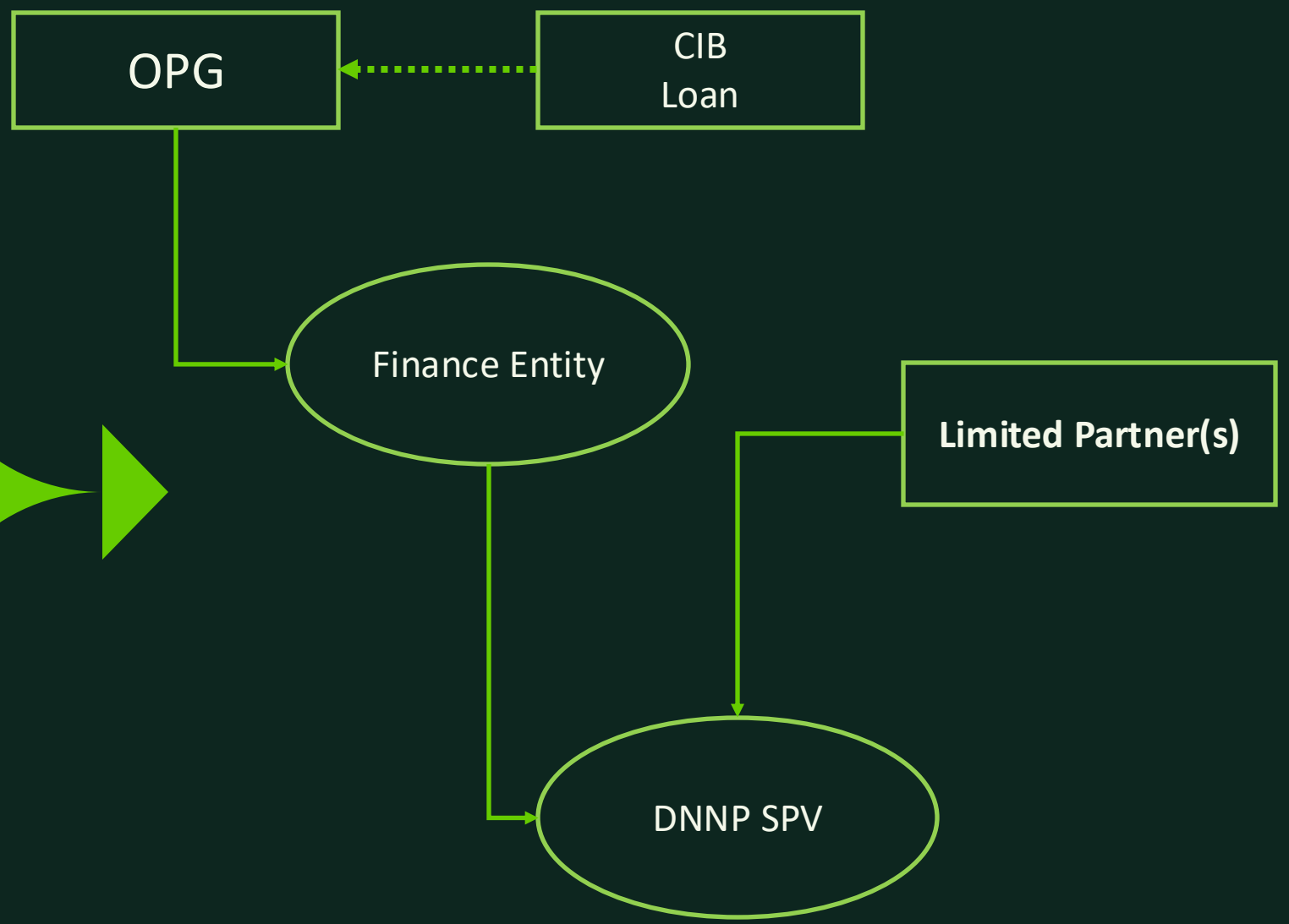
DNNP SPV Structure

DNNP Financial Structure

- OPG is seeking to develop the DNNP project through a Special Purpose Vehicle (SPV) structure in order to facilitate outside equity investment into the project.
- OPG has been in active negotiations for equity investments by Canada Growth Fund (CGF) and Building Ontario Fund (BOF) during the construction phase of the project.
- OPG has been engaging in good-faith discussions with certain of the Williams Treaties First Nations broadly in respect of the SMR, including exploring potential economic opportunities.
- It is expected that OPG and the equity partners will intend to seek SPV debt financing from public markets as soon as practicable following the first SMR coming online.

Expected Initial Ownership (During Unit 1 Construction)



OPG Confidential

Confidential and Commercially Sensitive

OPG / DNNP SPV Relationship

Manages Construction and Operates Facilities

OPG

OPG will hold CNSC Licences*

Lease

Project Management Agreement

Management, Operations, Maintenance & Administration Agreement

IESO Payments Allocation Agreement

Holds Financial Interest

DNNP SPV

SPV will hold all DNNP units and generating licence
SPV will have no employees
OPG will be majority owner of SPV

Unanimous Shareholder Agreement & Limited Partnership Agreement

OPG's Role	Agreement	DNNP SPV's Role
Landlord	Lease	Tenant
Project Manager / Service Provider	Project Management Agreement	Service Recipient
Operator / Service Provider	Management, Operations, Maintenance & Admin Agreement	Service Recipient
Agent / payments collection, allocation and settlement agent	IESO Payments Allocation Agreement	Service Recipient

**OPG will be responsible for decommissioning the Facility, including the CNSC license to decommission, and for nuclear waste and spent nuclear fuel. It is expected that these costs will be collected through OPG's regulated rates (i.e., over Pickering and Darlington generation) under the regulation amendments.*

Confidential and Commercially Sensitive

DNNP Rate Regulation

Background

Current Regulatory Framework

- OPG is the only generator subject to rate regulation by the OEB.
- OEB's regulation of OPG is set out in *Ontario Regulation 53/05* (O. Reg. 53/05), under section 78.1 of the OEB Act.
- OPG receives payment amounts ($/MWh) with respect to output that is generated at a generation facility (100% variable rate)

Amendments to O. Reg. 53/05 are required to:

- Establish a stand-alone rate-regulated special purpose vehicle (SPV) to enable OPG to enter into commercial partnerships for SMRs that are built as part of DNNP
- Establish associated rate-setting framework for the DNNP SPV.

Anticipated DNNP SPV Application Treatment

OPG (on behalf of SPV) will seek approval of:

- SPV's revenue requirement for DNNP including concurrent cost recovery of interest costs
- SPV's production forecast for DNNP
- A single $/MWh blended (with OPG) nuclear payment amount based on the above (one payment amount per year)
- OPG expects ongoing application of the Nuclear Development Variance account to capture the revenue requirement impacts of DNNP
- The application will request applicable deferral and variance accounts for the DNNP LP, which will be subject to OEB approval

Key Implication of DNNP SPV:

- SPV rate base will comprise project costs treated as leasehold improvements
- Standalone deemed capital structure
- SPV operating costs will comprise amounts charged at cost by OPG as operator of DNNP
- Nuclear liabilities remain with OPG, with impacts expected to be recovered through rates

Filed: 2026-04-22, EB-2025-0297
Exhibit L, C1-SEC-037
Attachment 1, Page 84 of 98

Darlington New Nuclear Project

- The total cost of the four-unit DNNP, including interest, cost escalation, and contingency, is currently estimated at approximately **$20.9 billion**, of which the first SMR will cost **$6.1 billion**, along with costs for systems and services common to all four SMRs planned as part of the project of **$1.6 billion**.
- OPG and its project partners will continue to refine the total estimated project cost during the definition phase of the remaining three units, incorporating lessons learned from the construction of the first SMR and the Darlington Refurbishment project.
- In May 2025, the Province of Ontario proposed potential changes in regulations that would establish a new mechanism for concurrent cost recovery to allow OPG to recover debt interest during the construction period of the DNNP and the Pickering Refurbishment project (if the project is approved to proceed). OPG continues to explore optimal financing arrangements in support of funding requirements for the planned capital investments.

March 2024	• Early-phase site preparation work for the first SMR was completed • Site clearing activities for the three additional SMRs were also completed
April 2024	• The CNSC announced that the existing environmental assessment is applicable to the BWRX-300 technology
2025	• The CNSC announced its decision to issue a power reactor construction licence to OPG, authorizing the construction of one SMR at the DNNP site • The Province announced its support of OPG to proceed with the execution phase of the first SMR at the DNNP site
2030	• Goal to deploy G7's first grid-scale SMR
Mid-2030s	• Projected in-service dates for the three additional SMRs, pending the Province and regulatory approvals by the CNSC

Filed: 2026-04-22, EB-2025-0297
Exhibit L, C1-SEC-037
Attachment 1, Page 85 of 98

Additional SMR Units

OPG is **advancing planning and licensing** for three additional SMRs at the Darlington site.

Four units would produce a total **1,200 MW**, equivalent to **powering 1.2 million homes.**

The four SMRs are expected to increase Canada's GDP by **$38.5 billion** over 65 years.

Over the next 65 years, OPG's SMR fleet is expected to sustain, on average, about **3,700 jobs** per year, including **18,000 jobs** per year during construction.

About **80% of project spending** will go to companies across Ontario and construction of the SMR fleet is expected to drive **$500 million** annually into the province's supply chain.

In March 2025, the Ministry of Environment and Climate Change announced **$55 million** to support the development of these SMRs.

Multiple units will allow common infrastructure to be shared across units, further **reducing cost.**

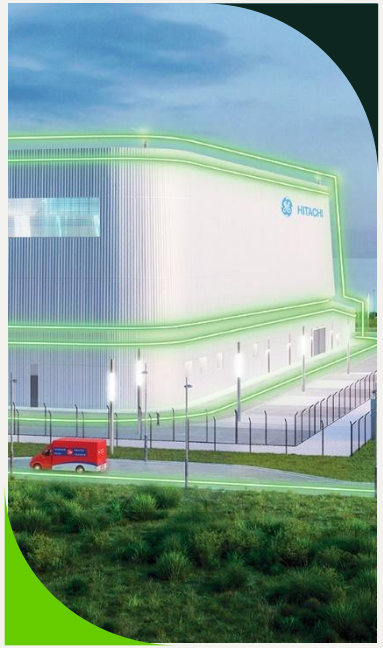


Small Modular Reactors

Benefits of this technology









Based on **existing technology**

Provides *safe, reliable, low carbon* power

Flexible, **scalable and modular**

Strong **economic benefits**

Building four 300MW SMRs in Ontario:

Create and sustain ~3,700 jobs

$38.5 billion to Canada's GDP

Reliable power to 1.2 million homes

One SMR will offset ~160,000 cars worth of carbon

Darlington New Nuclear Project

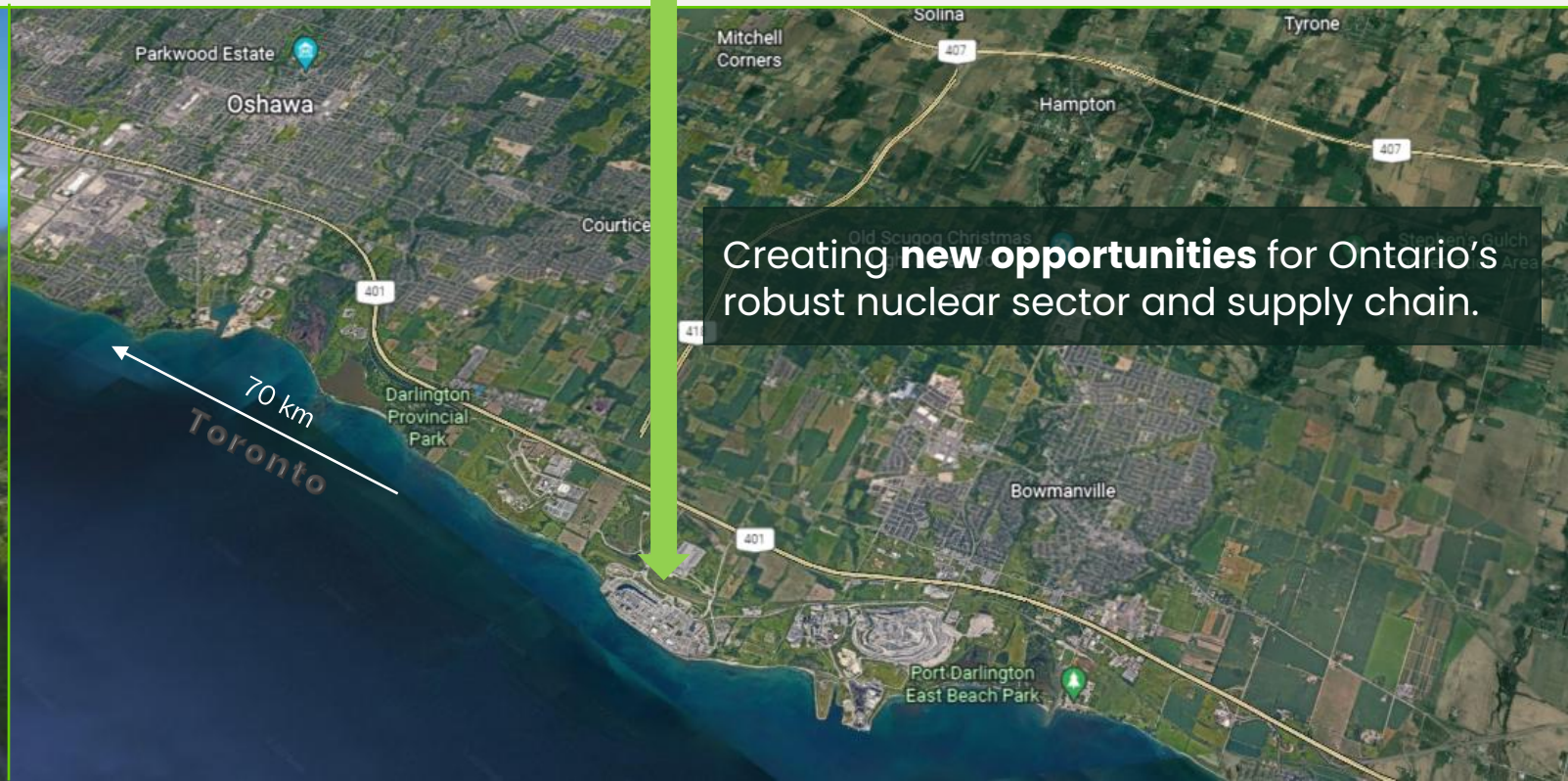
GE Hitachi: BWRX-300

Darlington New Nuclear Project Site
to the East of the Darlington Station

Darlington Site
1 Holt Rd South, Bowmanville ON Canada



Darlington Nuclear is the only site in Canada **licensed** for new nuclear build with an **accepted environmental assessment**.



Creating **new opportunities** for Ontario's robust nuclear sector and supply chain.



Project Goals and Objectives

Develop and build 4 SMRs at Darlington site

Develop fleet approach – collaborate with other owners/operators. Multi-unit supply chain strategy to reduce the overall cost.

Total cost of generation competitive in Canada's energy market – Design to Cost, Standard Plant, Modularization. Different way of managing a nuclear plant.

Learning – industry experience. Strong lessons learned program to ensure fleet approach is achieved for the product.

Innovation – build systems and culture to achieve our goals. This is imperative not only in construction but even more important in nuclear management systems including regulatory framework.

Integrated Project Delivery Model

Darlington New Nuclear Project

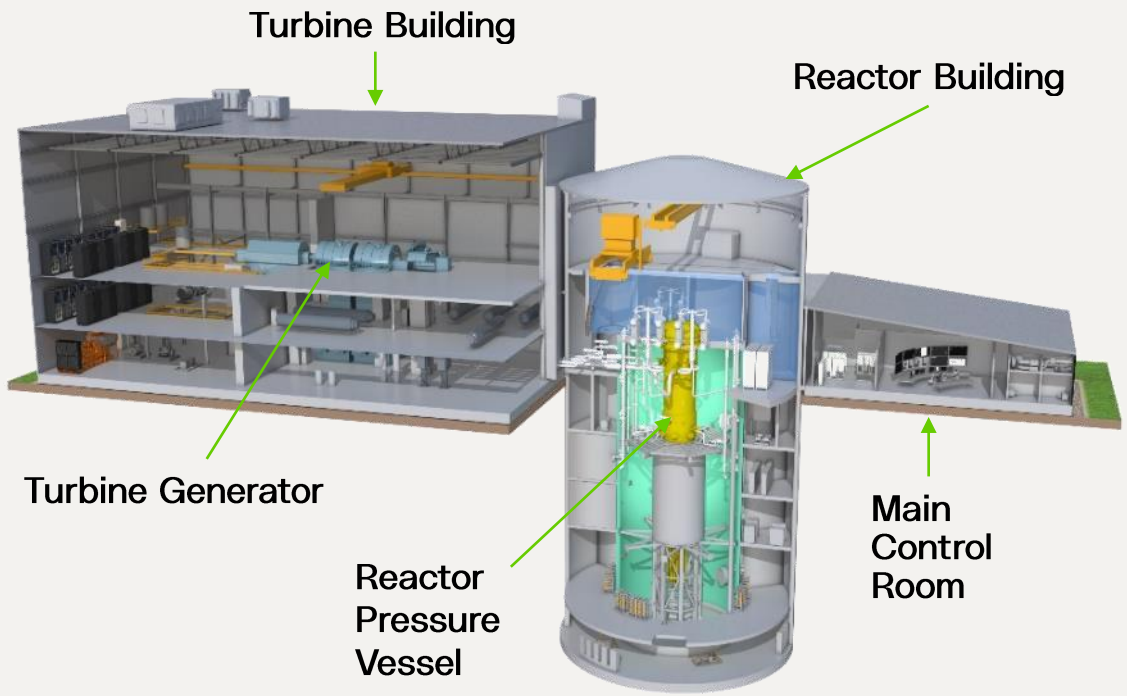
Owner and Licence Holder	Architect Engineer	Technology Developer	Constructor
ONTARIO POWER GENERATION	AtkinsRéalis	GE HITACHI	AECON

Why the Integrated Project Delivery (IPD) model?

- One team approach was a success on Darlington Refurbishment project
- Integrates people, systems, business structures and practices
- Joint management and collaborative decision making to achieve goals
- Unique cost and profit structures to promote teamwork

Technology Overview

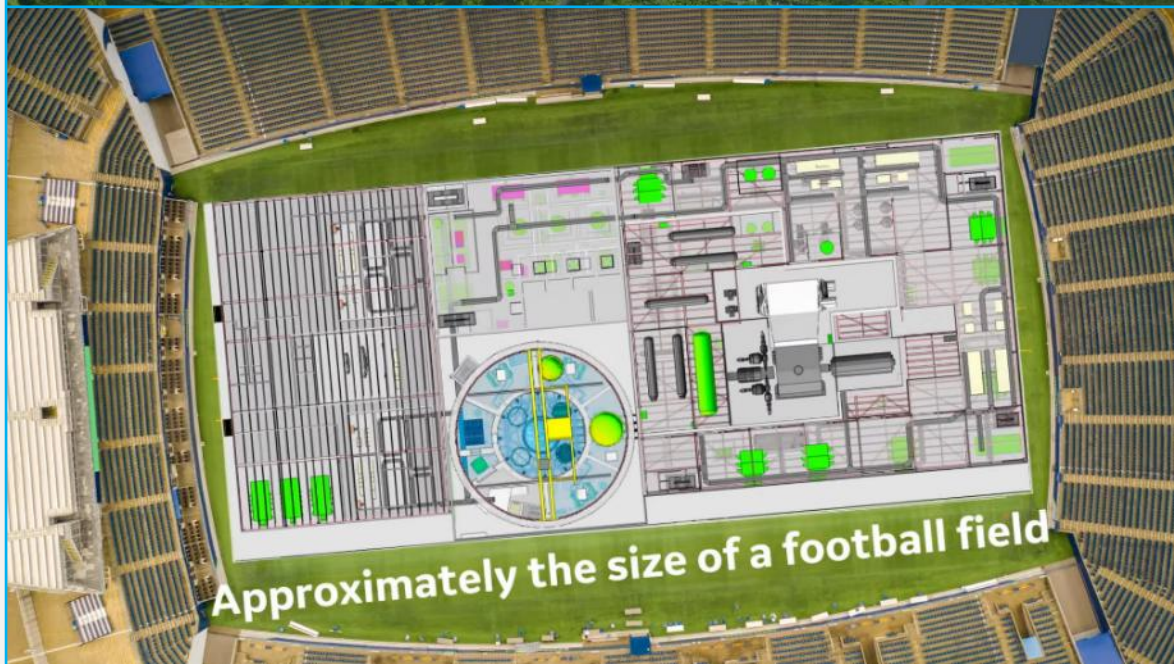
GE Hitachi: *BWRX-300*



Designed for a 60-year operational life

~300 megawatts, which is enough to power 300,000 homes

Boiling water reactor using natural circulation



GEH SMR Technologies Canada is the Canadian division of the world-leading provider of reactor technology and nuclear services.

DNNP Global Supply Chain

DNNP Global Map



Region of supply	% of supply chain value	Number of suppliers
Canada	48%	90 (89 in Ontario)
USA	10%	11
Europe (Italy, France, Germany, Spain)	17%	4
Japan	6%	1
TBD (sourcing still in progress, potential supply from Canada, USA, Mexico, Europe)	19%	TBD

Ontario Suppliers



Nuclear Fuel Supply Chain:

Supply Segment	Number of Contracts
Fuel fabrication and technical services	1
Uranium concentrates and uranium hexafluoride conversion services	2
Uranium enrichment services	2

TD Securities

Canadian Debt Capital Market Update

Debt Capital Markets

Week Ending October 17th, 2025

Canadian Credit Highlights

- Global markets were active last week amidst ongoing US / China tensions, the second week of US government shutdowns, and concerns over the private credit market as auto sector bankruptcies and Zions' filing on Thursday added to concerns about transparency in the banking system. However, strong corporate earnings results continued to reinforce investor optimism and pulled the market to a positive close by the end of the week
  - North American equities either side of unchanged (DOW down 0.17% while the S&P and NASDAQ were 0.30% - 0.70% higher, respectively), and GoC yields were 6 bps lower across the curve and outperformed the US decline of 1-2 bps, while C$ credit ended 1-2 bps wider on the week
- The primary market saw substantial activity despite the holiday shortened week, with ~C$3 billion of new issue supply across 6 issuers and 9 tranches
  - It's been a busy year for M&A related financings and **First National Financial** (BBB(low)) was the latest to the table, raising $800 million across a triple tranche 3-year, 5-year, and 7-year offering to redeem the company's existing unsecured notes as part of the company's take-private transaction by Birch Hill and Brookfield. The final order book was over $3.5 billion consisting of more than 40 accounts. Of note, the 3-year was the tightest spread ever for First National, the 5-year at $300 million was their largest, and their 7-year was their longest
  - **SmartCentres REIT** (BBB) dual-tranche $500MM offering, brought YTD real estate issuance beyond $10 billion as the sector remains incredibly active. The offering consisted of a new 3.6-year and 6.6-year which was anywhere from flat to 5 bps through fair value, with final pricing on both tranches representing Smart's tightest since 2020
  - **CES Energy Solutions** (BB(low)/B+) completed a $75 million re-opening of the bonds issued in May 2024 at a re-opening yield of 5.559% and **Sollio Cooperative Group** (BB) brought a $300 million new 7NC3 trade at 5.875%. Both high yield trades followed fixed income investor update calls and were met with solid investor response
  - **FortisBC Energy Inc.** (A/A3) was in the market with a new $200 million 5-year offering at GOC+65 bps. Given the absolute spread level, a minimal concession was required, and the final order book was 4.5x covered, consisting of nearly 40 buyers
  - **National Bank of Canada** (AA(low)/BBB+/A2/A+) capped off the week with a $1 billion 6NC5 senior bail-in offering at GOC+78 bps for 0 concession. Final order book was 3.5x covered with over 60 buyers
- In the secondary market, spreads closed the week 1-2 bps wider across every sector as investors digested the week's volatility
- This week in Canada brings September CPI data on Tuesday and Retail Sales on Thursday, while the US will get a September CPI reading on Friday. This will be a major data point to watch as the Fed prepares to make a decision on interest rates next week. The primary market is expected to remain busy.

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Canadian Debt Capital Market Update

Debt Capital Markets

Week Ending October 17th, 2025

Corporate New Issues

Announce Date	Issuer	Ratings	Amount ($mm)	Coupon (%)	Maturity	Spread (vs. curve)
14-Oct-25	**First National Financial Corporation**	**BBB(low)**	**$250**	**4.288**	**23-Oct-28**	**+175 bps**
14-Oct-25	**First National Financial Corporation**	**BBB(low)**	**$300**	**4.891**	**23-Oct-30**	**+215 bps**
14-Oct-25	**First National Financial Corporation**	**BBB(low)**	**$250**	**5.443**	**25-Oct-32**	**+250 bps**
14-Oct-25	FortisBC Energy Inc.	A/A3	$200	3.380	16-Oct-30	+65 bps
15-Oct-25	**Sollio Cooperative Group (7NC3)**	**BB**	**$300**	**5.875**	**03-Nov-32**	**+300 bps[1]**
15-Oct-25	**CES Energy Solutions Corp. (3.6NC0.6)**	**BB(low)/B+**	**$75**	**6.875**	**24-May-29**	**+303 bps[2]**
15-Oct-25	**SmartCentres Real Estate Investment Trust**	**BBB**	**$250**	**3.599**	**12-Jun-29**	**+102 bps**
15-Oct-25	**SmartCentres Real Estate Investment Trust**	**BBB**	**$250**	**4.318**	**12-Jun-32**	**+142 bps**
16-Oct-25	National Bank of Canada (6NC5)	AA(low)/BBB+/A2/A+	$1,000	3.441	21-Oct-31	+78 bps

Bold Indicates TD Securities Lead / Co-Lead

Total 2025 YTD Issuance: $128.1 billion

(1) vs CAN 2.00% 2032
(2) vs CAN 4.00% 2029

Government of Canada Yield Curve and Swap Spreads(1)

Term	Interpolated Yield	Left Benchmark Bond	Right Benchmark Bond	Swap Yield	Swap Spread
2 year	2.366%	2.75% September 2027	3.50% March 2028	2.212%	-14.0 bps
3 year	2.439%	3.25% September 2028	4.00% March 2029	2.278%	-16.5 bps
4 year	2.539%	3.50% September 2029	2.75% March 2030	2.345%	-19.0 bps
5 year	2.644%	2.75% September 2030	0.50% December 2030	2.419%	-20.8 bps
7 year	2.843%	2.00% June 2032	2.50% December 2032	2.577%	-22.1 bps
10 year	3.091%	3.25% June 2035	3.25% December 2035	2.790%	-26.6 bps
12 year	3.193%	5.00% June 2037	4.00% June 2041	2.910%	-19.6 bps
30 year	3.559%	2.75% December 2055		3.139%	-42.0 bps

(1) Source: Bloomberg, TD Securities. As of October 20, 2025

TD Securities

Canadian Debt Capital Market Update

Debt Capital Markets

Week Ending October 17th, 2025

Indicative Corporate New Issue Spreads

Levels shown are indicative spreads of where issuers could issue in the Canadian market. Spreads are vs the Government of Canada yield curve.

	Ratings				Term				
	DBRS	S&P	Moody's	Fitch	3	5	7	10	30
Bank									
Bank Senior Bail-in - TD (Bullet)	AA(low)	A-	A2	AA-	58	72	85	95	120
Bank Senior Bail-in - TD (Callable)	AA(low)	A-	A2	AA-	65	77	90	100	125
Bank Senior Bail-in - RY (Bullet)	AA	A	A1	AA-	54	68	81	91	116
Bank Senior Bail-in - RY (Callable)	AA	A	A1	AA-	61	73	86	96	119
Covered Bond - DSIBs	AAA	AAA	Aaa	-	37	47	57	67	87
NVCC Tier 2 - TD	A(low)	BBB+	A3(hyb)	A	N/A	115	135	155	180
NVCC Tier 2 - RY	A	A-	A3(hyb)	A	N/A	112	132	152	177
AT1 - TD	BBB(high)	BBB-	Baa2(hyb)	BBB+	N/A	310	N/A	335	N/A
AT1 - RY	A(low)	BBB	Baa2(hyb)	-	N/A	300	N/A	325	N/A
Fédération des caisses Desjardins du Québec (Bail-in)	AA(low)	A-	A1	-	58	72	85	95	120
Fédération des caisses Desjardins du Québec (Tier 2)	A(low)	BBB+	A2	-	N/A	119	139	159	N/A
Central 1 Credit Union (Senior)	A	-	-	A-	90	110	135	165	N/A
Central 1 Credit Union (Subordinated)	A(low)	-	-	BBB	N/A	165	195	225	N/A
Coast Capital Savings Credit Union	BBB(high)	-	-	-	120	145	N/A	N/A	N/A
Coast Capital Savings Credit Union (Subordinated)	BB(high)	-	-	-	N/A	375	N/A	N/A	N/A
Equitable Bank	BBB(high)	-	Baa1	-	100	120	N/A	N/A	N/A
EQB Inc. (LRCN)	BB	-	-	-	N/A	385	N/A	N/A	N/A
Fairstone Bank of Canada	BBB	-	-	-	135	160	N/A	N/A	N/A
First West Credit Union (Senior)	BBB(high)	-	-	-	155	180	N/A	N/A	N/A
First West Credit Union (Subordinated)	BBB	-	-	-	N/A	340	N/A	N/A	N/A
HomeEquity Bank	BBB(low)	-	-	-	185	225	N/A	N/A	N/A
CHIP Mortgage Trust	AAA	-	-	-	90	110	N/A	N/A	N/A
Laurentian Bank (Senior)	BBB	BBB	-	-	110	130	155	175	N/A
Laurentian Bank (Covered)	AA(high)	-	-	-	65	80	N/A	N/A	N/A
Laurentian Bank (Subordinated)	BB	BB+	-	-	N/A	240	N/A	N/A	N/A
Laurentian Bank (AT1)	BB(low)	BB-	-	-	N/A	445	N/A	N/A	N/A
Manulife Bank	AA(low)	A+	-	-	60	78	91	101	N/A
Insurance / Financial Services									
CI Financial Corporation	-	-	Baa3	-	190	230	N/A	N/A	N/A
IGM Financial Inc.	A(high)	A	-	-	60	75	85	100	125
Power Corporation of Canada	A	A+	-	-	60	75	85	100	125
Empire Life Insurance Company (Sub opco)	A	-	-	-	N/A	115	130	150	180
Empire Life Insurance Company (LRCN)	A(low)	-	-	-	N/A	320	N/A	345	N/A
Fairfax Financial Holdings Ltd.	A(low)	A-	Baa2	BBB+	78	93	103	123	148
First National Financial Corp. (Senior)	BBB(low)	-	-	-	175	215	250	N/A	N/A
Sagen MI Canada Inc.	A(high)	BBB+	-	-	140	170	200	230	N/A
Great-West LifeCo Inc. (Senior holdco)	A(high)	A+	-	A	55	65	82	92	118
Great-West Life Assurance (Sub opco)	A(high)	AA-	-	BBB+	N/A	85	101	125	155
Great-West LifeCo Inc. (LRCN)	A(low)	A-		BBB+	N/A	295	N/A	320	N/A
iA Financial Corporation (Sub holdco)	A(low)	A-	-	-	N/A	105	120	140	170
iA Financial Corporation (LRCN)	BBB(high)	BBB+	-	-	N/A	315	N/A	340	N/A
Intact Financial Corporation (Callable senior)	A(high)	-	A3	A-	68	88	98	108	128
Intact Financial Corporation (Hybrid)	BBB(high)	-	Baa2	BBB	N/A	305	N/A	330	N/A
Definity Financial Corporation	BBB(high)	-	-	-	80	95	110	120	145
Manulife Financial Corp. (Senior holdco)	A(high)	A	-	A	55	73	86	96	111
Manulife Financial Corp. (Sub holdco)	A	A-	-	A-	N/A	105	120	140	170
Manulife Financial Corp. (LRCN)	A(low)	BBB+	-	BBB	N/A	310	N/A	335	N/A
Manufacturers Life Insurance Co. (Sub opco)	AA(low)	A+	-	A	N/A	90	106	130	160
MCAP Commercial LP	BBB(low)	-	-	-	160	190	220	N/A	N/A
Sun Life Financial Inc. (Senior holdco)	A(high)	A+	-	-	55	65	82	92	118
Sun Life Financial Inc. (Sub holdco)	A	A	-	-	N/A	98	113	133	163
Sun Life Financial Inc. (LRCN)	A(low)	A-	-	-	N/A	300	N/A	325	N/A
TMX Group Ltd.	AA(low)	-	-	-	53	73	85	105	135
Auto / Captive Finance									
Toyota Credit Canada Inc.	-	A+	A1	-	64	74	89	104	N/A
Mercedes-Benz Canada Finance Inc.	A	A	A2	-	71	91	106	121	N/A
Honda Canada Finance Inc.	A(high)	-	A3	-	65	80	95	110	N/A
BMW Canada Inc.	-	A	A2	-	72	92	107	122	N/A
Daimler Truck Finance Canada Inc.	-	A-	A3	-	73	93	108	123	N/A
VW Credit Canada Inc.	-	BBB+	Baa1	A-	91	111	131	151	N/A
Hyundai Capital Canada	A	A-	A3	A-	80	98	113	128	N/A
General Motors Financial of Canada, Ltd.	BBB(high)	BBB	Baa2	-	100	125	150	N/A	N/A
Ford Credit Canada Co.	BBB(low)	BBB-	Ba1	BBB-	190	230	260	N/A	N/A
PACCAR Financial Corp	AA(low)	-	-	-	57	71	86	101	N/A
Caterpillar Financial Services Ltd.	-	A	A2	A+	57	71	86	101	N/A
John Deere Financial Inc.	-	A	A1	A+	57	71	86	101	N/A
Industrial / Other									
Magna International Inc.	-	A-	A3	-	80	105	125	150	190
Toromont Industries Ltd.	A(low)	-	-	-	65	80	95	115	155
Finning International Inc.	BBB(high)	BBB+	-	-	75	90	105	125	165
WSP Global Inc.	BBB(high)	-	-	-	70	90	105	125	170
Stantec	BBB	-	-	-	85	105	125	150	195
AtkinsRéalis Group Inc.	BBB(low)	BBB-	-	-	95	115	135	160	205
Stella-Jones Inc.	BBB	-	-	-	85	110	130	155	195
CAE Inc.	-	BBB-	-	-	130	155	180	210	265
Transcontinental Inc.	BBB(low)	BBB-	-	-	115	140	165	195	N/A
Teranet Holdings LP	BBB	BBB-	-	-	95	120	140	165	205

TD Securities

Canadian Debt Capital Market Update

Debt Capital Markets

Week Ending October 17th, 2025

Indicative Corporate New Issue Spreads

Levels shown are indicative spreads of where issuers could issue in the Canadian market. Spreads are vs the Government of Canada yield curve.

	Ratings				Term				
	DBRS	S&P	Moody's	Fitch	3	5	7	10	30
Utility									
Altalink LP	A	A-	-	-	50	62	77	92	113
AltaLink Investments LP	A(low)	A-	-	-	65	77	92	107	137
Alectra Inc.	A	A-	-	A	50	60	75	90	113
CU Inc.	A(high)	-	-	A	52	64	79	94	115
CU Ltd	A	-	-	A-	67	79	87	100	130
ATCO Ltd	A(low)	-	-	BBB+	77	89	102	115	145
Emera Inc.	-	BBB-	Baa3	BBB	85	105	120	140	175
Nova Scotia Power Inc.	BBB(high)	BBB-	-	-	75	90	105	120	140
Enbridge Gas Inc.	A	A-	-	-	57	70	82	98	121
Énergir	A	A	-	-	52	62	76	93	115
Noverco Inc.	-	BBB+	-	-	72	82	96	113	136
ENMAX Corp	BBB(high)	BBB	-	BBB	65	85	100	120	145
EPCOR Utilities Inc.	A(low)	-	-	A	52	63	75	90	115
FortisAlberta Inc.	A(low)	A-	-	-	53	65	80	95	115
FortisBC Inc.	A(low)	-	Baa1	-	73	86	101	116	140
FortisBC Energy Inc. (Terasen Gas)	A	-	A3	-	53	66	81	96	115
Fortis Inc.	A(low)	BBB+	-	BBB+	75	85	100	120	150
Hydro One Inc.	A(high)	A	A3	-	50	62	77	92	113
Liberty Utility Co.	BBB(high)	BBB	Baa2	BBB+	80	90	105	120	150
National Grid Electricity Transmission plc (Maple)	-	BBB+	Baa1	A-	70	90	105	125	155
Toronto Hydro Corp.	A	A+	-	-	50	59	72	87	111
TriSummit Utilities Inc.	BBB(high)	BBB	-	BBB+	80	100	120	140	170
Infrastructure / Transportation									
407 International Inc.	A	A	-	-	50	60	75	90	115
British Columbia Ferry Services Inc.	A(high)	A+	-	-	50	60	75	90	114
Nav Canada	-	AA	Aa2	-	48	55	65	80	105
Montreal Port Authority	-	AA	-	-	48	55	65	80	114
Vancouver Fraser Port Authority	-	AA	-	-	48	55	65	80	114
Calgary Airport Authority	-	-	A2	-	53	60	70	85	110
Greater Toronto Airports Authority	-	A+	Aa3	-	48	55	65	80	105
Heathrow Funding Ltd.	-	BBB+	-	A-	70	85	105	120	150
Canadian National Railway Company	A	A-	A2	-	55	65	75	97	119
Canadian Pacific Railway Company	BBB(high)	BBB+	Baa1	-	60	72	87	102	127
Pension Real Estate Entities									
AIMCO Realty Investors LP	AA(low)	-	-	-	52	70	85	97	117
BCI QuadReal Realty	AA(low)	-	-	-	52	70	85	97	117
Ivanhoé Cambridge II Inc.	AA(low)	-	-	-	52	70	85	97	117
Oxford Properties Group Trust	A(low)	-	-	-	62	80	100	112	132
Media / Telco / Technology									
AT&T Inc.	-	BBB	Baa2	BBB+	75	90	110	130	150
Bell Canada	BBB	BBB	Baa2	-	75	90	110	130	155
CGI Inc.	-	BBB+	A3	-	75	90	110	130	155
Cogeco Communications Inc.	BBB(low)	BBB-	-	-	90	110	130	155	185
Rogers Communications Inc.	BBB(low)	BBB-	Baa3	BBB-	75	90	110	130	155
TELUS Corp.	BBB	BBB-	Baa2	-	75	90	110	130	155
Thomson Reuters Corp	BBB(high)	A-	Baa1	A-	60	70	90	110	135
Verizon Communications Inc.	-	BBB+	Baa1	A-	65	80	100	120	145
Videotron Ltd.	-	BBB-	Baa3	-	75	90	110	130	155
Retail / Consumer Products									
Alimentation Couche-Tard Inc	-	BBB+	Baa1	-	60	80	95	115	150
Canadian Tire Corporation Ltd.	BBB	BBB	-	-	75	95	110	130	165
Dollarama Inc.	BBB(high)	-	-	-	60	75	90	115	145
George Weston Limited	BBB	BBB	-	-	85	105	120	145	170
Gildan Activewear Inc.	BBB	BBB-	Baa3	BBB	90	110	130	150	190
Loblaw Companies Limited	BBB(high)	BBB+	-	-	55	75	85	105	135
Metro Inc.	BBB(high)	BBB	-	-	55	75	85	105	135
Saputo Inc.	BBB(high)	-	Baa1	-	65	85	95	120	155
Sobeys Inc.	BBB	BBB-	-	-	75	95	105	125	155
Energy Infrastructure									
AltaGas Ltd.	-	BBB-	-	BBB	75	95	112	135	160
Enbridge Inc.	A(low)	BBB+	Baa2	BBB+	70	90	107	130	155
Enbridge Pipelines Inc.	A	BBB+	-	-	65	85	101	125	150
Gibson Energy Inc.	BBB(low)	BBB-	-	-	85	105	125	145	165
Husky Midstream LP	BBB	-	-	-	75	100	119	140	165
Inter Pipeline Ltd.	BBB(low)	-	-	BBB-	100	120	150	170	190
Inter Pipeline (Corridor) Inc.	A(low)	-	-	-	100	120	137	170	225
Keyera Corp	BBB	BBB	-	-	80	100	120	140	165
North West Redwater Partnership	A	A-	A3	-	65	75	90	105	125
Pembina Pipeline	BBB(high)	BBB	-	-	75	90	112	135	160
South Bow Canadian Infrastructure Holdings Ltd.	-	BBB-	Baa3	BBB-	80	105	125	140	170
TransCanada PipeLines Ltd.	BBB(high)	BBB+	Baa2	BBB+	70	90	108	125	150
Power Generation / Brookfield Entities									
Brookfield Corp.	A	A-	A3	A-	75	90	110	130	155
Brookfield Infrastructure Finance	-	BBB+	-	BBB+	80	95	113	135	160
Brookfield Renewable Partners ULC	BBB(high)	BBB+	-	BBB+	75	90	110	130	155
Bruce Power LP	BBB	-	Baa2	BBB+	60	80	92	110	135
BPC Generation Infrastructure Trust	-	-	-	BBB-	80	100	112	135	160
Capital Power Corp	BBB(low)	BBB-	-	-	85	105	122	145	175
Ontario Power Generation	A(low)	BBB+	A3	-	55	65	83	105	130

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Indicative Corporate New Issue Spreads

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	Ratings				Term				
	DBRS	S&P	Moody's	Fitch	3	5	7	10	30
Energy / Mining									
BP Capital Markets plc	-	A-	A2	A	50	70	90	110	135
Canadian Natural Resources Ltd.	A(low)	-	Baa1	BBB+	75	95	115	140	165
Cenovus Energy Inc.	BBB(high)	BBB	Baa1	BBB	80	100	120	145	170
Suncor Energy Inc.	A(low)	-	Baa1	BBB+	70	90	110	135	160
ARC Resources Ltd.	BBB	-	-	-	80	100	120	145	180
Tourmaline Oil Corp.	BBB(high)	-	-	-	70	90	110	135	175
Whitecap Resources Inc.	BBB	-	-	-	90	115	135	160	195
Cameco Corp.	BBB	BBB	Baa2	-	65	85	105	130	160
Glencore Finance (Canada) Ltd.	-	BBB+	A3	-	70	95	115	140	175
Unsecured Real Estate									
Choice Properties REIT	BBB(high)	BBB+	-	-	70	95	110	130	160
SmartCentres REIT	BBB	-	-	-	90	120	145	165	N/A
RioCan REIT	BBB	-	-	-	90	125	145	165	200
CT REIT	BBB	-	-	-	90	120	140	160	N/A
First Capital REIT	BBB	-	-	-	90	115	135	155	N/A
Primaris REIT	BBB(high)	-	-	-	90	110	135	155	N/A
Crombie REIT	BBB	-	-	-	90	120	145	165	N/A
Allied Properties REIT	BBB	-	-	-	140	165	185	215	N/A
Avenue Living 2014 LP	BBB(low)	-	-	-	190	215	240	270	N/A
Northwest Healthcare Properties REIT	BBB(low)	-	-	-	195	230	255	285	N/A
Brookfield Property Finance ULC	BBB(low)	BB+	-	-	220	255	280	330	N/A
Morguard Corporation	BB(high)	-	-	-	215	250	N/A	N/A	N/A
Prologis LP	-	A	A2	-	60	75	90	110	N/A
Granite REIT Holdings LP	BBB(high)	-	-	-	85	110	130	155	N/A
Dream Industrial REIT	BBB	-	-	-	90	115	135	160	N/A
Dream Summit Industrial Holdco Inc.	BBB	-	-	-	90	115	135	160	N/A
Welltower Inc. (HCN Canada Holdings-1 LP)	-	A-	A3	BBB+	65	85	100	120	N/A
Ventas Canada Finance Ltd.	-	BBB+	Baa1	BBB	80	100	115	135	N/A
Sienna Senior Living	BBB	-	-	-	80	105	125	150	N/A
Chartwell Retirement Residences	BBB(low)	-	-	-	85	115	135	160	N/A
Canadian Core Real Estate LP	A(low)	-	-	-	105	135	155	180	N/A
A Composite					59	73	87	103	125
BBB Composite					83	104	120	139	163

Issuers	Ratings (M / S / D)	5 Year	10 Year	30 Year
REITs				
Choice Properties	(- / BBB+ / BBBH)	92	130	155
CT REIT	(- / - / BBB)	115	155	180
Granite	(- / - / BBBH)	115	165	-
RETAIL & CONSUMER PRODUCTS				
Metro	(- / BBB / BBBH)	75	110	132
Loblaws	(- / BBB+ / BBBH)	75	110	135
Canadian Tire	(- / BBB / BBB)	100	135	160
TELECOM AND MEDIA				
Bell Canada	(Baa2 / BBB / -)	95	130	160
Telus	(Baa2 / BBB- / -)	95	135	160
Rogers Communications Inc.	(Baa3 / BBB- / -)	100	135	160
POWER GEN & UTILITIES				
Toronto Hydro	(- / A+ / A)	57	85	110
Hydro One	(A3 / A / -)	62	90	112
Alectra Utilities	(- / A- / A)	65	93	115
Fortis Inc	(Baa3 / A- / AL)	80	120	155
Capital Power	(Baa3 / A- / AL)	110	155	210
PIPELINES				
Enbridge Inc	(Baa2 / BBB+ / -)	90	130	155
TransCanada PipeLines Hybrid	(Baa2 / BBB+ / -)	95	125	150
Inter Pipeline Ltd.	(- / - / BBBL)	120	175	190
INFRASTRUCTURE / TRANSPORT				
407	(- / A / A)	55	90	117
GTAA	(Aa3 / A+ / AH)	48	78	103
BC Ferries	(- / A+ / AH)	68	93	120

CIBC

Debt Capital Markets

Indicative New Issue Spreads

October 20, 2025

BENCHMARK YIELDS									
Term				**2 years**	**3 years**	**5 years**	**7 years**	**10 years**	**30 years**
Coupon				2.75%	3.25%	2.75%	2.00%	3.25%	2.75%
Maturity				Sep-27	Sep-28	Sep-30	Jun-32	Jun-35	Dec-55
Yield				2.36%	2.43%	2.62%	2.81%	3.06%	3.56%
Benchmark Adjustment for Curve				0.7	1.1	1.8	3.0	3.4	-
	DBRS	**Moody's**	**S&P**	**SPREADS vs. Curve**					
BANKS									
Bail-In Notes (CIBC)	AA(l)	A2	A-	58	65	75	86	95	115
OIL & GAS									
Canadian Natural Resources	A(l)	Baa1	--	68	78	95	113	133	168
Cenovus Energy	BBB(h)	Baa1	BBB	73	83	100	118	138	173
Suncor Energy	A(l)	Baa1	--	65	75	92	110	130	165
TELCOS									
Bell Canada	BBB	Baa2	BBB	65	75	92	110	130	160
TELUS Corporation	BBB	Baa2	BBB-	65	75	92	110	130	160
Rogers Communications	BBB(l)	Baa3	BBB-	65	75	92	110	130	160
UTILITIES									
Alectra Inc.	A	--	A-	-	51	61	75	89	114
AltaGas Ltd.	--	--	BBB-	65	78	95	115	135	165
TriSummit Utilities	BBB(h)	--	BBB	65	85	102	119	135	165
Bruce Power L.P.	BBB	Baa2	--	57	67	82	97	115	142
Capital Power Corporation	BBB(l)	--	BBB-	83	95	115	135	155	-
CU Inc.	A(h)	--	--	-	-	62	75	90	115
Canadian Utilities Limited	A	--	--	-	-	73	87	102	127
Enbridge Gas Inc.	A	--	A-	50	60	70	83	98	123
Enbridge Pipelines	A	--	BBB+	58	68	85	103	123	153
Enbridge Inc.	A(l)	Baa2	BBB+	60	70	87	105	125	155
ENMAX Corporation	BBB(h)	--	BBB	63	73	88	103	123	170
EPCOR Utilities	A(l)	--	--	48	54	63	77	92	117
Emera	--	Baa3	BBB-	80	95	113	132	148	187
Nova Scotia Power	BBB(h)	--	BBB-	55	65	80	97	113	145
FortisAlberta	A(l)	Baa1	A-	-	-	67	80	95	120
FortisBC Energy	A	A3	--	47	55	65	77	92	117
FortisBC	A(l)	Baa1	--	50	60	72	87	102	132
Hydro One Inc.	A(h)	A3	A	44	50	60	74	88	113
Toronto Hydro	A	--	A+	43	49	58	72	86	111
TransCanada PipeLines	BBB(h)	Baa2	BBB+	58	68	85	103	123	153
Pembina Pipeline	BBB(h)	--	BBB	62	75	92	110	130	160
Gibson Energy	BBB(l)	--	BBB-	68	80	98	120	140	170
Keyera	BBB	--	BBB	65	78	95	115	135	165
Inter Pipeline	BBB(l)	--	--	80	97	122	145	167	200
INFRASTRUCTURE									
407 International	A	--	A	41	48	61	71	92	117
BC Ferries	A(h)	--	A+	47	53	63	77	90	115
NAV CANADA	--	Aa2	AA-	37	43	53	69	82	101
Greater Toronto Airports Authority	--	Aa3	A+	42	48	55	70	82	107
RETAIL									
Canadian Tire	BBB	--	BBB	52	62	80	97	120	152
Dollarama Inc.	BBB(h)	--	--	47	55	72	90	112	142
George Weston	BBB	--	BBB+	60	70	88	104	126	161
Loblaw Companies	BBB(h)	--	BBB+	47	55	70	87	107	137
Metro Inc.	BBB(h)	--	BBB	45	53	70	85	105	135
Sobeys Inc	BBB	--	BBB-	57	65	83	102	126	165

EXHIBIT E

MOMA Indicative Terms

This term sheet (the "**Term Sheet**") is intended to summarize certain material terms of the MOMA, pursuant to which the Operator will provide management, operation, maintenance and administration services to ProjectCo LP. Other terms and other details regarding the terms summarized below and additional customary terms and conditions will be negotiated and provided for in the definitive MOMA. In addition, each Party acknowledges that OPG is in discussions with the Williams Treaty First Nations regarding their commercial participation in the DNNP and the terms of the definitive agreement contemplated by this Term Sheet may be subject to change based on the outcome of these discussions.

Capitalized terms not otherwise defined in this Term Sheet or the Equity Commitment Agreement (including the other term sheets attached thereto as Exhibits B, C, D and F) will be defined in the definitive MOMA.

This Term Sheet applies to the Facility only and does not apply to any other nuclear reactors and the associated electrical generating units and other infrastructure that may be located outside of the Leased Premises, now or in the future.

1.	**Service Provider / Operator:**	The Operator
2.	**Service Recipient:**	ProjectCo LP, through ProjectCo GP acting in its capacity as managing general partner of ProjectCo LP. All references to ProjectCo GP in this Term Sheet refer to ProjectCo GP, acting in its capacity as managing general partner of ProjectCo LP unless noted otherwise.
3.	**MOMA:**	The MOMA will be prepared by the Operator and will incorporate the provisions of this Term Sheet, other provisions customarily included in commercial agreements similar to the MOMA, and any other provisions which the Operator and ProjectCo GP mutually agree.
4.	**Term of MOMA:**	The term of the MOMA will be the same as the term of the Lease Agreement (the "**Term**"), provided, however, that, subject to the following sentence, the MOMA shall automatically terminate upon the termination of the Lease Agreement or the Project Management Agreement prior to the expiration of their respective terms. Notwithstanding the foregoing, the Operator will continue to provide administration services to ProjectCo GP (acting in its own capacity and in its capacity as managing general partner of ProjectCo LP) and ProjectCo LP following the end of the Term as required to wind-up ProjectCo GP and ProjectCo LP's affairs. The parties agree that the MOMA cannot be terminated for any reason,

including in the event of a material breach, except as expressly contemplated in this Term Sheet.

5. Scope of Services: The Operator will provide all services required to manage, operate, maintain, modify, improve, repair and administer the Facility and to administer ProjectCo LP and ProjectCo GP, as further described in Schedule A and as will be more specifically detailed in the definitive MOMA (the "**Services**").

6. Appointment and Authority of the Operator: ProjectCo GP will, for the duration of the Term, irrevocably and exclusively appoint the Operator as "operator" to:

(a) provide the Services; and

(b) enter into (or continue to be party to), as agent and nominee for and on behalf of ProjectCo GP, any Project Agreements. The definitive MOMA will specify whether the Operator should enter into the Fuel Agreement (as defined in the IPA) in its own capacity or as agent and nominee for and on behalf of ProjectCo GP.

The Operator will provide the Services in accordance with the MOMA and have authority over the care, custody and control of the Facility, subject to the control and direction of ProjectCo GP as outlined in this Term Sheet (including as provided in Section 19 of this Term Sheet) and the definitive MOMA.

Without limiting the generality of the foregoing, but subject to the control and direction of ProjectCo GP as outlined in this Term Sheet and the definitive MOMA, the Operator will have the authority, during the Term, to provide the Services, including, to the extent related to the provision of Services, to:

(i) negotiate, execute and deliver on behalf of ProjectCo GP any contract, agreement, document or other instrument, and amending, extending or terminating the same, on terms considered reasonable to the Operator;

(ii) administer and manage all Project Agreements;

(iii) retain, on behalf of ProjectCo GP, pursuant to Project Agreements, goods and services providers, contractors, technical and other advisors under the Operator's supervision (it being understood that any person with whom the Operator contracts as agent and nominee of ProjectCo GP will be ProjectCo GP's counterparty and not a Service Provider Party for all purposes hereunder);

(iv) incur any expense and authorize payments on behalf of ProjectCo GP in connection with the performance of the Services, including all amounts payable to the Operator under the definitive MOMA that are not

reasonably disputed by ProjectCo LP, acting in good faith[1];

(v) make all applications and filings with Governmental Authorities required to be made on behalf of ProjectCo GP and ProjectCo LP;

(vi) control and direct the conduct of all regulatory proceedings in connection with the Facility and/or a Unit Facility, as applicable, or the Services; and

(vii) give any consent, waiver or instruction under any Project Agreement.

For clarity, but subject to the control and direction of ProjectCo GP as outlined in this Term Sheet (including as provided in Section 19 of this Term Sheet) and the definitive MOMA, the Operator will have the authority, during the Term, to take, or refrain from taking, any action related to the Services to the extent consistent with the Conditions of Performance.

ProjectCo GP will furnish the Operator with such specific powers of attorney, directions, certificates of authority, notices and such other evidence of authority, as requested by the Operator, to document the Operator's authority under the MOMA for the provision of the Services.

ProjectCo GP will be bound by and perform, observe and carry out, as necessary, all actions, obligations and restrictions undertaken or agreed to by the Operator pursuant to the authority granted under the MOMA for the provision of the Services.

The definitive MOMA will delineate the scope between the MOMA and the Project Management Agreement (including as it relates to the commissioning of a Unit). For clarity, all OEB-related activities, including rate applications and licence-related matters, will be the responsibility of the Operator under the MOMA.

In addition, the definitive MOMA will delineate OPG's roles and responsibilities, in its capacities as Operator and Landlord, respectively, for the interim management of used nuclear fuel and other radioactive waste on the Leased Premises arising from the Facility. To the extent the Operator has responsibility for such matters, such matters will form part of the Services and recovery of costs charged to ProjectCo LP in connection therewith will be sought by ProjectCo LP in the same manner as other costs payable under the MOMA through the OEB regulated rates.

The parties acknowledge and agree that the delegation of authority granted to the Operator as operator under the MOMA is required as the Operator will be the CNSC licensed operator of the Facility.

[1] The definitive MOMA will provide that amounts reasonably disputed in good faith can be withheld.

The Operator will be responsible for obtaining and maintaining all CNSC licences required to operate and maintain the Facility. Notwithstanding anything in this Term Sheet and the definitive MOMA, and for greater clarity, the Operator shall have full authority and discretion to act, or refrain from acting, as required to comply with Applicable Law (including any CNSC operating licence for the Facility or any part thereof) and the costs incurred by the Operator in connection therewith shall be reimbursed to it by ProjectCo LP hereunder.

7. Conditions of Performance:

The Operator will perform the Services and fulfil its other obligations under the MOMA:

(a) in accordance with all Applicable Laws (including all Authority Requirements and all Permits, Licences and Approvals);

(b) in accordance with the nuclear safety and security practices and culture adopted and promoted by OPG at other nuclear facilities owned and/or operated by OPG from time to time;

(c) subject to and without limiting paragraphs (a) and (b) above, in accordance with:

(i) Prudent Industry Practices;

(ii) applicable manufacturer and designer specifications and operations and maintenance manuals so as to: (A) keep the Facility in good operating condition, ordinary wear and tear excepted, and (B) keep all warranties with respect to the Facility, or any part thereof, in full force and effect;

(iii) applicable contractual obligations under the Project Agreements, to the extent that such contractual obligations relate to the performance of the Services; and

(iv) the requirements of the insurance policies maintained in respect of the Facility and the Services; and

(d) subject to and without limiting paragraphs (a), (b) and (c) above, using Prudent Industry Practices to maximize the Facility availability and to optimize its useful life,

(collectively, the "**Conditions of Performance**"), provided that, notwithstanding the foregoing and any other provision to the contrary in the MOMA, the Operator will not be liable to ProjectCo GP or ProjectCo LP for any failure by the Operator to satisfy the Conditions of Performance except to the extent set out in Section 28 of this Term Sheet below.

Should there be any conflicts or inconsistencies between any of the individual Conditions of Performance, the Operator will decide

how to resolve the conflict or inconsistency in good faith, acting reasonably, using Prudent Industry Practices.

ProjectCo GP acknowledges and agrees that the Operator does not guarantee or warrant any minimum capacity, availability or performance of the Facility or that the Facility will operate at all. The Operator will, as part of the Services, enforce the warranties and performance guarantees provided under the Project Agreements for the benefit of ProjectCo LP.

8. Independent Expert: As at the end of each fiscal year following Facility COD, the Operator shall calculate the Unit Capability Factor (defined by reference to the World Association of Nuclear Operators (WANO) Performance Indicator Programme Reference Manual or superseding or succeeding document) (the "**UCF**") in respect of the Facility for the then preceding three fiscal year period and provide such calculation to ProjectCo GP. If such UCF is below a percentage to be determined and specified in the definitive MOMA, ProjectCo GP may engage a third-party expert acceptable to the Operator, acting reasonably, to review the Operator's performance and provide recommendations with respect thereto. The Operator will consider any such recommendations in good faith, acting reasonably, provided that the Operator may ultimately accept or reject implementing such recommendations in its sole discretion. If the Operator rejects implementing a recommendation made by a third party expert appointed pursuant to this Section 8, it will (x) provide ProjectCo LP with the Operator's reasons for doing so, and (y) provide ProjectCo LP with a summary of the material steps that the Operator is taking and intends to take to improve its performance, as applicable. The third party expert cannot be a competitor to OPG (to be further defined in the definitive MOMA).

ProjectCo LP will be entitled to require that any individual employed by or seconded to the Operator who commits fraud, intentional misrepresentation or willful misconduct in connection with the provision of the Services no longer be involved, directly or indirectly, in the provision of the Services; provided, however, that if such individual is not dedicated exclusively to the Facility, the Operator shall be required to remove such individual from the direct or indirect provision of the Services only to the extent practicable.

9. Non-Discrimination: Without limiting the other obligations contained in the MOMA, to the extent that services comparable to a Service provided by the Operator are also used internally by OPG or provided by the Operator to its Affiliates or a third party (including as it relates to managing outages or energy generation), the Operator will provide the Service to ProjectCo GP at the Facility in a fair and reasonable

and non-discriminatory manner and will not give undue preference or priority to OPG, its Affiliates or such other Person, as applicable, including any of the other facilities in the OPG Combined Nuclear Fleet. For clarity, (a) the Operator will not provide Services to, or withhold Services from, ProjectCo GP with the specific intent of maximizing the economic return to OPG from the OPG Nuclear Fleet at the expense of ProjectCo LP and (b) this Section 9 does not apply to OPG's engagement of any individual employed by or seconded to the Operator that is dedicated to sites or projects that are not the Facility, to the extent the decision to dedicate such employees or secondees has not been made with the specific intent of harming ProjectCo LP, and OPG shall have no obligation to reassign or re-deploy any such dedicated employees or secondees to the Facility. The definitive MOMA will set out principles for the Operator to follow in the event that it needs to allocate available resources between the OPG Nuclear Fleet, any other facility in respect of which OPG provides services and the Facility or to the Services.

The Operator will ensure that its Affiliates comply with this Section 9.

10. Subcontracting, Labour and Employment:

The Operator will:

(a) furnish and make available as necessary the labour and professional, supervisory, managerial and senior oversight Service Provider Personnel required to perform the Services, including key contact persons in respect of the Services. All such persons will remain within the sole authority, control and responsibility of the Operator or its Affiliates or Service Provider Parties, as applicable, including with respect to the determination of working hours and rates of compensation. For clarity, the cost and impact of labour negotiations and any labour disruptions experienced by the Operator or its Affiliates to the extent that they relate to the provision of the Services by Service Provider Personnel of the Operator or its Affiliates will be passed on to ProjectCo LP. The settlement of any strikes, lockouts or labour disputes under labour agreements and the negotiation of any labour agreements relating to such Service Provider Personnel will be in the sole discretion of the Operator or its Affiliates, as applicable;

(b) manage all matters pertaining to selection, training, supervision, direction, compensation, working conditions, availability, termination, safety and related matters pertaining to the Service Provider Personnel; and

(c) ensure that Service Provider Personnel performing any part of the Services are duly qualified with the requisite

experience, skills and capacity necessary to perform the relevant Services.

The Operator shall be permitted to subcontract aspects of the performance of the Services, provided that no subcontracting or delegation by the Operator to any Service Provider Party will relieve the Operator of its obligations under the MOMA. The Operator will enforce its rights against the Service Provider Parties to the benefit of ProjectCo LP.

11. CNSC Licences: The Operator will hold the CNSC Operating Licence and all future CNSC operating licenses relating to the Facility or the Services and will manage all regulatory proceedings and communications in respect thereof.

12. Other Permits, Licenses and Approvals: The Operator and ProjectCo GP will each hold an OEB generation license.

13. Expense Reimbursement: Without limiting the Operator's ability to allocate shared costs to ProjectCo LP in accordance with the other provisions of this Section 13, in consideration for the Services, ProjectCo LP will reimburse the Operator monthly for all of its fully allocated, fully burdened costs (including overhead) incurred or accrued in performing the Services, including, to the extent incurred in performing the Services:[2]

(a) (i) the costs of any Service Provider Personnel, including the cost of terminating any Service Provider Personnel (including at the end of the Term) and the pension and other post-employment benefits of any Service Provider Personnel; and (ii) the costs of any Service Provider Party engaged by the Operator to perform any aspect of the Services (including, for clarity, the costs of any disputes between the Operator and any other Service Provider Party);

(b) the costs in connection with the provision of letters of credit or other assurances or guarantees in connection with the operation and maintenance of the Facility;

(c) any fees or expenses incurred by the Operator in performing the obligations under the Project Agreements, including for greater certainty, any Owner Own Costs or Owner Deemed Project Chargeable Costs (as such terms are defined in the IPA);

[2] The precise delineation of such obligations in respect of the decommissioning and the used nuclear fuel and other radioactive waste from the Facility will be further detailed in the definitive MOMA and the definitive Lease Agreement.

(d) nuclear fuel costs, as more specifically described in Section 24;

(e) the costs of purchasing and maintaining materials and spare parts inventories for use at the Facility;

(f) the direct or indirect costs of the Operator's internal support functions, such as security, procurement, contract management, risk management and oversight, regulatory affairs, legal, human resources, finance, training, information technology management, and stakeholder management; and

(g) the costs of all information technology systems and infrastructure or software developed, maintained or used in connection with the performance of the Services,

but excluding, for clarity, any amounts for which the Operator is required to indemnify ProjectCo GP pursuant to the MOMA (or OPG, in another capacity, is required to indemnify ProjectCo LP or ProjectCo GP pursuant to the other Transaction Documents).

In addition, the Operator will charge ProjectCo LP [redacted] he mechanics of determining and settling such monthly financing charge will be further detailed in the definitive MOMA.

For clarity, the foregoing reimbursements shall be made without duplication of reimbursements made by ProjectCo LP to OPG, as Project Manager under the Project Management Agreement, or recovery by OPG, in respect of the OPG Nuclear Fleet, through regulated rates established by the OEB.

Any shared costs, whether operating or capital in nature, will be subject to an allocation mechanism to determine ProjectCo LP's share of the Operator's costs in line with the Operator's then current cost allocation methodology based on principles acceptable to the OEB.[3] Any disputes relating to ProjectCo LP's share of the Operator's costs shall be resolved in accordance with the Dispute Resolution Procedure (as defined below).

Each of the Operator and ProjectCo LP will notify the other party upon learning of an error in the expense reimbursements made

[3] Any shared costs will be subject to an allocation mechanism to determine ProjectCo LP's share of the Operator's costs in line with the Operator's then current cost allocation methodology based on principles acceptable to the OEB, which will be detailed in the definitive MOMA.

under the MOMA and, as soon as practicable thereafter, the Operator and ProjectCo LP will resolve such error and make any resulting payments required to correct such error, plus interest at a specified rate. If the Operator and ProjectCo LP are unable to rectify such error within 30 days of the notice then the matter will be settled in accordance with the Dispute Resolution Procedure.

The Operator will advise ProjectCo LP in writing if there are capital costs (other than in certain to-be-defined circumstances) that it intends to incur in connection with the provision of the Services and for which it does not expect to seek recovery of such costs from the OEB in a future rate application. In addition, the Operator will identify (i) in each Draft Rate Period Business Plan, any OM&A Costs (as defined below) for which it does not intend to seek recovery through OEB regulated rates; and (ii) in each Draft Annual OM&A Base Budget, any OM&A Costs, which, had they been included in the Approved Rate Period Business Plan in respect of the Rate Period partially comprised by the period covered by such Draft Annual OM&A Base Budget, the Operator would not have sought recovery thereof through OEB regulated rates.

All amounts paid by ProjectCo LP under the MOMA are exclusive of HST and other applicable taxes.

14. Government Funding

To the extent that government funding programs are or become available after the Closing for the Facility, the Operator will apply therefor, for and on behalf of ProjectCo LP, to the extent eligible. If ProjectCo LP is not eligible for such funding but the funding is available to OPG, in its capacity as Project Manager, Operator or in any another capacity, OPG shall apply for the funding and contribute the amounts received in respect of the Facility to ProjectCo LP (without issuance of additional units) or otherwise make such amounts available to ProjectCo LP (e.g., by reducing the amount of its reimbursable expenses under the Project Management Agreement or the MOMA, without duplication). Notwithstanding the foregoing, the provisions of this Section 14 shall in no way apply to any funding, programs or benefits of any kind (including financing) made available to OPG or any of its Affiliates, in any capacity, by OPG's shareholder.

15. Business Plans:

Prior to the submission of each cost-based rate application to the OEB on ProjectCo LP's behalf, the Operator will prepare a draft business plan (each, a "**Draft Rate Period Business Plan**") for ProjectCo LP during a period that covers, at a minimum, the period

to be covered by the OEB application (the "**Rate Period**").[4] The Draft Rate Period Business Plan will be approved[5] in accordance with the Unanimous Shareholders Agreement (once approved, each an "**Approved Rate Period Business Plan**"). For clarity, the Approved Rate Period Business Plan will form the basis for such OEB application, as applicable.[6]

In addition, following the approval of an Approved Rate Period Business Plan in accordance with the Unanimous Shareholders Agreement and prior to each fiscal year covered by that Approved Rate Period Business Plan (other than the first such fiscal year), the Operator will prepare a draft updated business plan (each, a "**Draft Updated Business Plan**") for ProjectCo LP for the period from the start of that fiscal year to the end of the applicable Rate Period. The Draft Updated Business Plan will be approved[7] in accordance with the Unanimous Shareholders Agreement (once approved, each an "**Approved Updated Business Plan**"). Each Approved Rate Period Business Plan and Approved Updated Business Plan shall constitute an "**Approved Business Plan**".

16. Operating, Maintenance and Administration Base Budgets:

It is expected that the Operator will prepare and include in each cost-based OEB application, as applicable, and based on the Approved Rate Period Business Plan, a forecast of all the annual operating, maintenance and administration costs for the Facility ("**OM&A Costs**")[8] for each fiscal year in the applicable Rate Period (which, for clarity, may include OM&A Costs to be incurred before a Unit achieves Commercial Operation) (each, an "**Annual OM&A Cost Rate Period Forecast**").

For each fiscal year during a Rate Period, the Operator will prepare, as part of a Draft Rate Period Business Plan or a Draft Updated Business Plan (each a "**Draft Business Plan**"), a draft annual OM&A base budget for ProjectCo LP (each, a "**Draft Annual OM&A Base Budget**"), which will include all OM&A Costs, except for those related to any Planned Outage, (collectively, "**OM&A Base Costs**") reasonably expected to be incurred during the applicable fiscal year. The Draft Annual

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4 As applicable, a Draft Business Plan will have an operating component, which will be prepared by the Operator pursuant to the MOMA, and a project component, which will be prepared by the Project Manager pursuant to the Project Management Agreement.

5 Under the Unanimous Shareholders Agreement, this matter will be (i) during the period prior to the Standalone Date, a Shareholder Reserved Matter; and (ii) from and after the Standalone Date, a Board Matter.

6 For clarity, if the 2027-2031 Rate Application is filed before the Transaction Documents become effective, these procedures will not apply to the 2027-2031 Rate Application.

7 Under the Unanimous Shareholders Agreement, this matter will be (i) during the period prior to the Standalone Date, a Shareholder Reserved Matter; and (ii) from and after the Standalone Date, a Board Matter.

8 While nuclear fuel costs are considered in OM&A Costs in this Term Sheet for simplicity, the definitive MOMA will reflect nuclear fuel costs as a separate category to be included in a Draft Business Plan and in the cost-based OEB Rate Application based on the Approved Rate Period Business Plan.

OM&A Base Budget will be approved[9] in accordance with the Unanimous Shareholders Agreement (once approved, each an "**Approved Annual OM&A Base Budget**"). For clarity, the budget and expenditure process outlined in this Section 16 shall not apply to the DNNP Costs.

The Operator may not incur OM&A Base Costs in a fiscal year (a) in excess of 110%, but less than or equal to 120%, of the applicable Approved Annual OM&A Base Budget without obtaining approval of the Board; or (b) in excess of 120% of the applicable Approved Annual OM&A Base Budget, without obtaining approval of the Shareholders as a Supermajority Approval Matter; provided, however, that costs resulting from any of the conditions, events or circumstances described in Schedule B (the "**Enumerated Conditions**") shall be excluded from the calculations as to whether the foregoing thresholds have been exceeded. The Operator will present to the Board for discussion the facts and circumstances surrounding any OM&A Base Costs, the incurrence of which would require the approval of the Board or the Shareholders pursuant to the preceding clauses (a) and (b), as applicable, but for the fact that such OM&A Base Costs result from any of the Enumerated Conditions, and to the extent reasonably requested by a Shareholder entitled to nominate a director, be the subject of an organized discussion between representatives of the Operator and representatives of the Shareholders wishing to participate. For clarity, the presentation and discussion covenants contemplated by the preceding sentence shall not affect the Operator's ability to incur and be reimbursed for the OM&A Base Costs in question in accordance with the terms of the MOMA.

17. Operating, Maintenance and Administration Planned Outage Budgets:

For each fiscal year during a Rate Period, the Operator will prepare, as part of a Draft Business Plan, a draft annual OM&A planned outage budget for the Facility (each, a "**Draft Annual OM&A Planned Outage Budget**"), which will include all OM&A Costs related to any planned outage (collectively, "**OM&A Planned Outage Costs**") reasonably expected to be incurred during the applicable fiscal year. The Draft Annual OM&A Planned Outage Budget will be approved[10] in accordance

[9] Board Matter until Facility COD. From and after Facility COD: (i) the approval of any proposed Draft Annual OM&A Base Budget that exceeds 120% of the OM&A Base Costs that were included in the Annual OM&A Cost Rate Period Forecast in respect of the fiscal year to which the proposed Draft Annual OM&A Base Budget relates (after adjustments to account for any Enumerated Conditions) will be a Supermajority Approval Matter; and (ii) the approval of any other proposed Draft Annual OM&A Base Budget will be a Board Matter.

[10] Board Matter until Facility COD. From and after Facility COD: (i) the approval of any proposed Draft Annual OM&A Planned Outage Budget that exceeds 120% of the OM&A Planned Outage Costs that were included in the Annual OM&A Cost Rate Period Forecast in respect of the fiscal year to which the proposed Draft Annual OM&A Planned Outage Budget relates (after adjustments to account for any Enumerated Conditions and to account for changes in the assumed timing of any planned outage contemplated in the Approved Rate Period

with the Unanimous Shareholders Agreement (once approved, each an "**Approved Annual OM&A Planned Outage Budget**"). For clarity, the budget and expenditure process outlined in this Section 17 shall not apply to the DNNP Costs.

The Operator may not incur OM&A Planned Outage Costs in a fiscal year (i) in excess of 110% of the applicable Approved Annual OM&A Planned Outage Budget without obtaining approval of the Board; or (ii) in excess of 120% of the applicable Approved Annual OM&A Planned Outage Budget, without obtaining approval of the Shareholders as a Supermajority Approval Matter; provided, however, that costs resulting from any of the Enumerated Conditions shall be excluded from the calculations as to whether the foregoing thresholds have been exceeded. The Operator will present to the Board for discussion the facts and circumstances surrounding any OM&A Planned Outage Costs, the incurrence of which would require the approval of the Board or the Shareholders pursuant to the preceding clauses (i) and (ii), as applicable, but for the fact that such OM&A Planned Outage Costs result from any of the Enumerated Conditions, and to the extent reasonably requested by a Shareholder entitled to nominate a director, be the subject of an organized discussion between representatives of the Operator and representatives of the Shareholders wishing to participate. For clarity, the presentation and discussion covenants contemplated by the preceding sentence shall not affect the Operator's ability to incur and be reimbursed for the OM&A Planned Outage Costs in question in accordance with the terms of the MOMA.

Business Plan that partially comprises such fiscal year) will be a Supermajority Approval Matter; and (ii) the approval of any other proposed Draft Annual OM&A Planned Outage Budget will be a Board Matter.

18. Capital Expenditures and Improvements: For each fiscal year following the year in which Unit 1 achieves COD, the Operator will prepare, as part of a Draft Business Plan, a draft annual budget (each, a "**Draft Annual Post-COD CapEx Budget**") for capital expenditures for the Units that have then achieved COD ("**Post-COD CapEx Costs**"). The Draft Annual Post-COD CapEx Budget will be approved[11] in accordance with the Unanimous Shareholders Agreement (once approved, each an "**Approved Annual Post-COD CapEx Budget**"). For clarity, the capital expenditure budget process outlined in this Section 18 shall not apply to the DNNP Costs.

In connection with the foregoing, the Operator will, from time to time, recommend to the Shareholders any capital improvements, excluding DNNP, necessary or advisable in accordance with the Conditions of Performance, to repair, rectify, refurbish, upgrade, sustain, enhance, reconstruct or otherwise improve the performance or functionality of the Facility. Such recommendations shall be accompanied by a description of the proposed budget for the relevant capital improvement, the reasons therefor and the benefits to be derived therefrom, all in reasonable detail. For clarity, the DNNP Costs are not subject to this Section 18.

19. Board and Shareholder Approvals: The Operator will provide ProjectCo GP with advance written notice of any proposed action (including the incurrence of costs) that is subject to the approval of the Shareholders under the Unanimous Shareholders Agreement, or a to be specified list of proposed actions that will require approval of the Board, and will not take such proposed action (or incur such costs) unless and until ProjectCo GP obtains the requisite approval of the Shareholders and/or the Board, as applicable.

20. Provision of Reports: The Operator will, among other things:

(a) promptly notify the Board in writing and provide particulars in reasonable detail in respect of: (i) any material defects or deficiencies in the Facility discovered by the Operator; (ii) any forced outages or significant malfunction of any equipment of the Facility discovered by the Operator which might reasonably be expected to have a material adverse effect; (iii) any material breach of Applicable Law by the Operator or any Service Provider Party relating to the Services or the Facility, any investigation, non-routine enquiry, or non-routine

[11] Board Matter, provided that if the budgeted capital expenditures in respect of a project are expected to exceed $500,000,000 (adjusted for inflation using the applicable indices to be defined) at the time the project proceeds to execution, Supermajority Approval of such project expenditures will be required (for clarity, such approval would be sought for the full project expenditures, not only the associated annual expenditures).

inspection of any part of the Facility, by any Governmental Authority; (iv) any occurrence, accident, safety violation, lawsuit or claim by any person which would reasonably be expected to result in an investigation or penalty under Applicable Laws; (v) any material violation of any Condition of Performance by the Operator or any Service Provider Party; (vi) any actual, threatened or reasonably anticipated litigation in respect of the Facility, ProjectCo GP or ProjectCo LP; (vii) any Encumbrance against the Facility, ProjectCo GP or ProjectCo LP; and (viii) any circumstances that a reasonable and prudent operator of nuclear power generation facilities would reasonably expect to result in adverse reputational consequences for ProjectCo GP or ProjectCo LP;

(b) make available to the Board copies of any material correspondence with any Governmental Authority related to the Services or the Facility;

(c) within a number of Business Days (to be set out in the definitive MOMA) following the end of each calendar quarter, provide the Board a reasonably detailed written report in respect of the operations and maintenance of the Facility during such quarter, which will include the following:

(i) the OM&A Base Costs incurred during such quarter together with an explanation of material deviations, if any, as compared to the OM&A Base Costs budgeted for such quarter in the applicable Approved Annual OM&A Base Budget;

(ii) the OM&A Planned Outage Costs incurred during such quarter together with an explanation of material deviations, if any, as compared to the OM&A Planned Outage Costs budgeted for such quarter in the applicable Approved Annual OM&A Planned Outage Budget;

(iii) the Post-COD CapEx Costs incurred during such quarter together with an explanation of material deviations, if any, as compared to the applicable Approved Annual Post-COD CapEx Budget;

(iv) a description of the significant activities and projects carried out during such quarter together with an explanation of material deviations, if any, as compared to the then most recent Approved Business Plan;

(v) a description of any material safety, regulatory, contractual and environmental issues identified by the

Operator during such quarter, and the impact of the same (if any) on the then most recent Approved Business Plan and/or the Facility; and

(vi) the electricity generation from the Facility during such quarter, including details of planned and unplanned outages, power delivered to the IESO Controlled Grid on a day by day basis, and the Unit Capability Factor in respect of each Unit for such quarter; and

(d) provide the assistance, reports and additional information reasonably required by the shareholders of ProjectCo GP to allow them to comply with Applicable Laws and their internal policies, including with respect to their reporting requirements regarding environmental, social and governance impacts. To the extent the Operator is requested to provide assistance pursuant to the preceding sentence, the Operator reserves the right to charge the costs of such assistance to the requesting shareholder.

21. Property License:

During the Term, ProjectCo LP will grant to the Operator an exclusive license of use and access to, on and over the Leased Premises, the Facility and any tools and equipment owned by ProjectCo LP to the extent required by the Operator to perform the Services (the "**Property License**"), provided that, for clarity, the Project Manager will also be provided the Property License and Representatives of ProjectCo LP will be provided reasonable access to the Leased Premises and the Facility.

The Operator may grant sub-licenses of the Property License to any Person to the extent required by the Operator to perform the Services, including to the NOPs, as required under the IPA, and to any other counterparty to a Project Agreement, as required under such Project Agreement.

22. Intellectual Property Ownership and Licenses:

Pursuant to the IPA and related agreements, ProjectCo LP will receive all of the "Owner" rights in respect of Intellectual Property thereunder (the "**Facility IP**"), provided that ProjectCo LP will grant the Operator a royalty-free, worldwide, perpetual, irrevocable, sub-licensable, exclusive licence to the Facility IP (solely to the extent of ProjectCo LP's rights therein), provided that, for clarity, the Project Manager will be provided a substantially similar licence under the Project Management Agreement and ProjectCo LP will be entitled to use the Facility IP only for the Facility Purposes. The Operator will agree to sub-license the Facility IP to subcontractors or other Service Provider Parties as is required to provide the Services.

To the extent any Intellectual Property is created by a party, alone or together with others, in connection with the Services or the

MOMA (the "**MOMA IP**"), as between the parties, ProjectCo LP shall be the owner or rights holder (as applicable) of all such MOMA IP, provided that ProjectCo LP will grant the Operator a royalty-free, worldwide, perpetual, irrevocable, sub-licensable, exclusive licence to the MOMA IP (solely to the extent of ProjectCo LP's rights therein), provided that, for clarity, the Project Manager will be provided a substantially similar licence under the Project Management Agreement and ProjectCo LP will be entitled to use the MOMA IP only for the Facility Purposes. The Operator will agree to sub-license the MOMA IP to subcontractors or other Service Provider Parties as is required to provide the Services.

23. Insurance:

The Operator will be responsible for obtaining and maintaining all insurance required to be obtained and maintained by ProjectCo LP under the Project Agreements in ProjectCo LP's name and will add the Operator as a named insured in all such policies, provided that, subject to the other provisions of the MOMA, ProjectCo LP will be responsible for the costs thereof and any deductibles or self-insured retentions for which ProjectCo LP is responsible under the Project Agreements. The MOMA will set forth a list of insurance required to be obtained and maintained by ProjectCo LP.

ProjectCo LP will carry nuclear property damage insurance, which will provide the recourse in respect of damage to the Facility as a result of a Nuclear Incident (except as set out in Section 25(c)).

24. Nuclear Fuel:

On or before COD in respect of Unit 1 and periodically thereafter (as determined by the Operator), the Operator will prepare for the Board a plan for acquiring the nuclear fuel necessary to operate the Facility. The Operator, as operator of the Facility, will at all times retain title to and responsibility for all nuclear fuel used in the operation of the Facility. The costs in respect thereof will be paid by ProjectCo LP under the MOMA in the manner to be detailed in the definitive MOMA. For clarity, the nuclear fuel costs charged to ProjectCo LP under the MOMA will include a cost of capital charge on nuclear fuel inventory carried by the Operator for use at the Facility at the then OEB-approved weighted average cost of capital for ProjectCo LP.

25. Nuclear Liability:

(a) The Operator, as operator of the Facility, will bear all liability imposed on the operator under the *Nuclear Liability and Compensation Act* (Canada), and will carry the insurance required under that Act.

(b) ProjectCo LP will have no right to claim and/or recover from the Operator in respect of or in relation to damage to the Facility or any equipment or property located at the Facility or the site, arising from any Nuclear Incident, whether in law or equity, and whether based upon an action

or Claim in contract, tort (including negligence and negligent misrepresentation), warranty, equity, strict liability, statutory cause of action, intended conduct or otherwise, and any such right to so claim and/or recover will be irrevocably waived by ProjectCo LP. It will be a condition to the transfer of any equity interest in ProjectCo LP that the transferee deliver such waiver to the Operator.

(c) Notwithstanding paragraph (b), the Operator will be responsible for damage to the Facility as a result of a Nuclear Incident to the extent that such damage is wholly or partly caused by an unlawful act or omission of the Operator committed with intent to cause injury or damage, but only up to the lesser of (i) the amount of the nuclear property damage insurance deductible, self-insured retentions and retained losses and (ii) [redacted] being subject to an annual adjustment to account for inflation beginning in the first year following COD of Unit 1), without duplication with the analogous provision of the Project Management Agreement.

(d) The Operator will use all reasonable efforts to have the Leased Premises prescribed as the lands for the "nuclear installation" designation for the Facility under the *Nuclear Liability and Compensation Act* (Canada) by the time the CNSC operating licence is issued to the Operator.

(e) Except in connection with the proceeds of ProjectCo LP's nuclear property damage insurance policy to which it is entitled, the Operator will have no recourse to ProjectCo LP, its limited partners, ProjectCo GP and its shareholders in connection with or arising from a Nuclear Incident whether in law or equity, and whether based upon an action or Claim in contract, tort (including negligence and negligent misrepresentation), warranty, equity, strict liability, statutory cause of action, intended conduct or otherwise, and any such right to so claim and/or recover will be irrevocably waived by the Operator. It will be a condition to the assignment of the MOMA and to any subcontract that the assignee or subcontractor, as the case may be, deliver such waiver to ProjectCo LP.

26. ProjectCo LP Indemnity to the Operator:

ProjectCo LP will indemnify and save harmless the Operator, its Affiliates, and its and their respective directors, officers, employees, secondees and other staff members (each, an "**Operator Indemnitee**") from and against any and all Direct Losses which may be suffered, sustained or incurred by them in connection with a Claim brought against them by a third party as a result of, in respect of, or arising, directly or indirectly, out of, or

in consequence of, or involving or relating to, the performance of the MOMA, including the provision of the Services, by or on behalf of the Operator, except in each case (i) to the extent as a result of fraud, intentional misrepresentation or willful misconduct by any Operator Indemnitee, or (ii) any amounts for which OPG, in another capacity, is required to indemnify ProjectCo LP or ProjectCo GP pursuant to the IESO Payments Agreement, the Lease Agreement or the Project Management Agreement.

27. Operator Indemnity to ProjectCo LP: The Operator will indemnify and save harmless ProjectCo LP and each ProjectCo LP Party (each, an "**ProjectCo LP Indemnitee**") from and against any and all Direct Losses which may be suffered, sustained or incurred by or brought against one or more of the ProjectCo LP Indemnitees as a result of fraud, intentional misrepresentation or willful misconduct by any Operator Indemnitee, provided that and notwithstanding the foregoing, this indemnity in respect of any Nuclear Incident at the Facility shall be limited to that set out in Section 25(c).

28. Limit on Liability: Except as set out in Section 25(c) and Section 27, ProjectCo LP will have no right to claim and/or recover from any Operator Indemnitee any Losses which may be suffered, sustained or incurred by or brought against one or more of ProjectCo LP Indemnitees as a result of, in respect of, or arising, directly or indirectly, out of, or in consequence of, or involving or relating to, the performance or breach of the MOMA, including the provision of the Services, by or on behalf of the Operator, whether in law or equity, and whether based upon an action or Claim in contract, tort (including negligence and negligent misrepresentation), warranty, equity, strict liability, statutory cause of action, intended conduct or otherwise.

29. Books and Records, Access and Information Rights: The Operator will keep or cause to be kept, for a period of time to be agreed by the parties in the definitive MOMA (the "**Retention Period**"), complete and accurate books and records reflecting the assets, liabilities, income and expenses of ProjectCo GP and of ProjectCo LP in accordance with generally accepted accounting standards and Applicable Law and shall make such books and records available to each of the Shareholders and its auditor and legal counsel to examine and make copies of such books and records. The books and records to be kept by the Operator pursuant to the preceding sentence shall be so kept in a manner that is separate and distinct from the books and records of OPG.

During the Retention Period, the Operator shall make available to ProjectCo GP and ProjectCo LP and their auditors such books and records of the Operator that are relevant to Operator's compliance with its obligations under the MOMA.

30.	**Representations and Warranties:**	Usual and customary for operation and maintenance agreements similar to the MOMA.
31.	**Specific Performance:**	The MOMA will contain a customary specific performance clause.
32.	**Dispute Resolution:**	All disputes will be determined in accordance with a schedule to be agreed by the parties (the "**Dispute Resolution Procedure**"), which, among other things, (i) will be uniform across all of the definitive agreements between the parties relating to the Facility, (ii) will contain an escalation mechanism to discuss and attempt to resolve any breach of the parties' respective obligations and (iii) will provide for the allocation, as between the parties, of the costs incurred by each party in connection with the dispute. The resolution of disputes pursuant to such schedule will be final and binding upon the parties and there shall be no appeal therefrom.
33.	**Governing Law:**	The MOMA will be construed and governed by the laws of the Province of Ontario and the federal laws of Canada as applicable therein.
34.	**Assignment:**	The assignment provisions will be substantially consistent with those reflected in Exhibit C to the Equity Commitment Agreement (*Lease Agreement Indicative Terms*), provided that the Operator shall also be entitled to assign or transfer the MOMA to a "Qualified Successor Operator" if concurrently, (a) OPG has assigned or transferred (i) the IESO Payments Agreement and the Project Management Agreement (each to the extent it remains in full force and effect), and (ii) (x) its direct or indirect Equity Interests in ProjectCo LP and ProjectCo GP in accordance with the Limited Partnership Agreement and the Unanimous Shareholders Agreement, and (y) the OPG ECA (to the extent it remains in full force and effect), in each case to that Qualified Successor Operator (or, in respect of such Equity Interests, to a designee of such Qualified Successor Operator, which designee must be a wholly-owned Affiliate of such Qualified Successor Operator), and (b) the Qualified Successor Operator has assumed all of OPG's obligations under the IESO Payments Agreement, the Project Management Agreement (each to the extent it remains in full force and effect), the OPG ECA (to the extent it remains in full force and effect) and the MOMA.

35. Acknowledgement of Other Business Interests:

Without derogating from the Operator's obligations under the MOMA, ProjectCo LP acknowledges that the Operator and its Affiliates (a) without limiting Sections 9 and 10, will not, and are not required to, exclusively devote their personnel and resources for the benefit of the Facility, and (b) are or, subject to Applicable Laws, may become engaged, directly or indirectly, in a variety of other business interests which include the ownership, financing, development, construction, operation and management of electricity generating stations.

Each party acknowledges and agrees that the other party, its shareholders and its and their Affiliates or any of their respective officers, directors or employees may have other business interests, even though such business interests may be similar to or competitive with those of ProjectCo LP.

36. Rate Application:

The Operator will prepare and submit to the OEB a rate application on ProjectCo LP's behalf, on a regular cadence, subject to the requirements of the OEB and Applicable Law. Each such application shall: (a) be based on reasonable assumptions, including, as applicable, as to the Facility's anticipated electricity generation, OM&A Costs, and capital expenditures, based on the Approved Rate Period Business Plan; (b) as applicable, request recovery of corporate income taxes or payments in lieu thereof under the *Electricity Act, 1998* (Ontario) for any partners that are subject to regular corporate income taxes or payments-in-lieu of taxes thereof under the *Electricity Act, 1998* (Ontario); (c) be prepared in a manner that does not discriminate against ProjectCo LP or the Facility relative to other generating assets that may be included in such rate application; and (d) be approved[12] in accordance with the terms of the Unanimous Shareholders Agreement.

For clarity, in seeking recovery in a rate application to the OEB in respect of any expenditures, including return thereon, of ProjectCo LP, the Operator shall have discretion to propose reductions on account of ITCs on the same basis it would do so if the OPG Partner were the sole Equity Partner unless it was certain at the time of the submission of such rate application that the OPG Partner would be ineligible for ITCs for expenditures in respect of the Facility, subject to the requirements of the OEB.

[12] Under the Unanimous Shareholders Agreement, this matter will be (i) during the period prior to the Standalone Date, a Shareholder Reserved Matter; and (ii) from and after the Standalone Date, a Board Matter.

SCHEDULE A

SCOPE OF SERVICES[13]

ProjectCo LP will retain the Operator to provide all of the operations, maintenance, management and administrative services (other than those provided under the Project Management Agreement or the IESO Payments Agreement, while in effect), as may be necessary or advisable for ProjectCo LP to carry on its business, including:

1. **Pre-Commercial Operation Operating Services** – the Operator will provide the following Services prior to COD of each Unit:

   (a) Performing, as agent and nominee of ProjectCo LP, some or all of the "Owner's" obligations under the IPA relating to the commissioning of the Facility (with the precise scope of Services relating to the commissioning of the Facility to be further described in the definitive MOMA and the definitive Project Management Agreement), including, without limitation, some or all of:

      (i) providing the Service Provider Personnel to serve on the Commissioning and Turnover PMT;

      (ii) carrying out the Commissioning; and

      (iii) Reviewing Turnover information packages.

   (b) Procuring the Fuel Assemblies required for Commissioning from Fuel Co under the Fuel Agreement;

2. **Post-Commercial Operation Operating and Maintenance Services** – the Operator will provide the following Services from and after COD in respect of Unit 1:

   (a) Operation and dispatch of the Facility, including price and quantity of offers into the IESO markets.

   (b) Interfacing with all governmental authorities as may be required in respect of the day-to-day operational functions of the Facility.

   (c) Outage related services (e.g., determining the timing of outages subject to required IESO approval and completing work with respect thereto).

   (d) Providing equipment and tools required for operating, maintaining and undertaking any improvements of the Facility which are not owned by ProjectCo LP.

   (e) Coordinating elements of the Services to be provided by Service Provider Parties.

[13] The description of the Services in this schedule are indicative only and will be further developed as part of finalizing the definitive MOMA. All services that ProjectCo LP requires during the Facility's operational period will be provided by a combination of (i) the Operator under the MOMA and (ii) the Project Manager under the Project Management Agreement.

(f) Procuring the fuel assemblies for operation of the Facility.

(g) Procuring and making available as necessary the materials, equipment, parts and goods required to perform the Services.

(h) Taking actions required to keep the Facility, ProjectCo LP and ProjectCo GP free of encumbrances.

(i) Taking actions required for ProjectCo LP to comply with its obligations under the Lease Agreement and the Project Agreements.

(j) Pursue, defend and/or settle claims or other litigation, arbitration or administrative proceedings involving the Facility.

(k) Taking any actions required for ProjectCo LP to comply with its end of term handback obligations under the Lease Agreement.

3. **Administrative Services** – the Operator will provide the following Services throughout the Term:

(a) Back office and administrative services.

(b) At the request of any ProjectCo LP partner, assisting with: (i) the direct or indirect sale by such partner of their interests in ProjectCo LP and ProjectCo GP; and (ii) any direct or indirect financing activities undertaken by any ProjectCo LP partner or its Affiliates in respect of its interest in ProjectCo LP and ProjectCo GP, provided that, as set out in the Exhibit D to the Equity Commitment Agreement (*Unanimous Shareholders Agreement and Limited Partnership Agreement Indicative Terms*), such partner will be pay for all reasonable costs incurred in respect thereof.

(c) Preparing Draft Rate Period Business Plans, Draft Updated Business Plans, Draft Annual OM&A Base Budgets, Draft Annual OM&A Planned Outage Budgets, Draft Annual Post-COD CapEx Budgets, the OEB rate applications, and the reports contemplated in Section 19 of this Term Sheet.

(d) Preparing plans for acquiring the nuclear fuel necessary to operate the Facility as contemplated in Section 24 of this Term Sheet.

(e) Preparing the financial statements and other reports required to be prepared by ProjectCo GP and delivered to its shareholders or the partners of ProjectCo LP under the Unanimous Shareholders Agreement or the Limited Partnership Agreement.

(f) The services required to be performed by OPG under the IESO Payments Agreement upon termination of the IESO Payments Agreement and the facilitation of payments to ProjectCo LP of revenue earned by ProjectCo LP in respect of the Facility.

4. **Exclusions from the Services** – The following services and obligations do not form part of the Services:

   (a) The obligations of, and services to be performed by, OPG under the IPA, except as specifically provided otherwise.

For clarity, the precise delineation between the work to be performed by OPG, as Landlord under the Lease Agreement, and the Services insofar as they relate to the interim management of used nuclear fuel and other radioactive waste from the Facility will be further detailed in the definitive MOMA and the definitive Lease Agreement.

SCHEDULE B

ENUMERATED CONDITIONS

"**Enumerated Conditions**" means any of the following conditions, events or circumstances, each as will be more specifically detailed, as applicable, in the definitive applicable Transaction Documents:

1. any difference between the Consumer Price Index or other measure of inflation assumed in a Approved Business Plan, Annual OM&A Cost Rate Period Forecast, Approved Annual OM&A Base Budget, Approved Annual OM&A Planned Outage Budget or Approved Annual Post-COD CapEx Budget (each, a "Plan", "Forecast" or "Budget", as applicable, for purposes of this definition only), as applicable, and the actual Consumer Price Index or other applicable measure of inflation at a given time;

2. any action taken or payment made by the Operator or the Project Manager as required to comply with Applicable Law where such action or payment was not contemplated in a Plan, Forecast or Budget, as applicable;

3. any difference between the foreign exchange rates assumed in a Plan, Forecast or Budget, as applicable, and the actual foreign exchange rates at a given time;

4. any difference between the terms of collective agreements applicable to unionized employees of OPG (or its Affiliates) assumed in a Plan, Forecast or Budget, as applicable, and the actual terms of collective agreements applicable to such employees at a given time;

5. the occurrence of an unplanned outage in respect of a Unit;

6. the occurrence of a *force majeure* event;

7. any difference between the pension and other post employment benefit costs and obligations assumed in a Plan, Forecast or Budget, as applicable, and the actual amount of such costs and obligations at a given time;

8. any difference between the premiums, expenses, deductibles, self-insured retentions or other costs of insurance assumed in a Plan, Forecast or Budget, as applicable, and the actual amount of such costs at a given time;

9. any difference between the amounts payable by ProjectCo GP or ProjectCo LP pursuant to the Lease Agreement and the IESO Payments Agreement assumed in a Plan, Forecast or Budget, as applicable, and such actual amounts payable at a given time;

10. any difference between the costs associated with nuclear fuel (including, for clarity, the costs associated with uranium, enrichment and fabrication) assumed in a Plan, Forecast or Budget, as applicable, and the actual amount of such costs at a given time; and

11. any other conditions, events or circumstances as the Parties may agree to include in the definitive applicable Transaction Documents.

Board Staff Interrogatory #021

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / p. 9
Ref 2: Exhibit I1 / Tab 2 / Schedule 1 / Table 2
Ref 3: Exhibit C1 / Tab 1 / Schedule 1 / Tables 1-5

Preamble:

For the years 2028-2031, OPG proposes that its hydroelectric payment amount be adjusted annually according to a mechanistic custom price-cap adjustment, using a formula that includes a Custom Capital Factor.

At Exhibit I1, OPG has shown its "Calculation of Capital Factor for Regulated Hydroelectric Facilities" which includes the following amounts that have been allocated from Exhibit C1. OEB staff has prepared Table 1 below showing these amounts.

Table 1 – Cost of Capital Amounts included in the Calculation of Capital Factor ($ millions)

	2028	**2029**	**2030**	**2031**
Short-Term Debt	$7.3	$8.0	$7.8	$6.7
Long-Term Debt	$215.1	$246.3	$265.1	$280.2
Return On Equity	$458.9	$512.3	$543.4	$568.8

Exhibit C1 shows the "Summary of Capitalization and Cost of Capital – OPG" for the years 2027 to 2031, which itemizes OPG's proposed recovery of short-term debt, long-term debt, and return on equity. These amounts are included in the proposed regulated hydroelectric facilities' revenue requirement for 2027 and the proposed nuclear facilities' revenue requirements for 2027 to 2031. These amounts are also embedded in the proposed regulated hydroelectric facilities' price-cap adjustment for 2028 to 2031 (specifically in the Capital Factor).

Question(s):

a) Please confirm that “Table 1 – Cost of Capital Amounts included in the Calculation of Capital Factor” is accurate. Please update the table as applicable and explain any changes made.

b) If OPG’s proposed Capital Factor is not approved by the OEB, how does OPG propose to recover the cost of capital amounts in Table 1 (or a revised Table that are provided in its Exhibit C1 evidence for the years 2028 to 2031? Please explain.

Response

a) Confirmed. OPG notes that this information is also provided in Ex. I1-2-1, Table 2, Note 2.

b) OPG has not contemplated a methodology for setting regulated hydroelectric payment amounts that excludes the proposed capital factor and therefore has no alternative proposal for recovery of the cost of capital amounts in Table 1. The rate-setting proposal, as described in Ex. A1-3-2, Section 2.0, is:

> … to set payment amounts for the prescribed hydroelectric facilities using a price-cap index Custom IR framework, consistent with the approach applied for the 2017-2021 period in EB-2016-0152, but with the addition of a custom capital factor (“C-factor”) and an adjustment factor to hold gross revenues charges (“GRC”) and other water agreement costs embedded in payment amounts constant over the IR term (“GRCF”).

Board Staff Interrogatory #022

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / p. 1
Ref 2: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1
Ref 3: Exhibit A2 / Tab 2 / Schedule 1 / Attachment 1 / p. 3
Ref 4: EB-2020-0290, Decision and Order, November 15, 2021; Settlement Agreement / Exhibit 0 / Tab 1 / Schedule 1 / p. 24, July 16, 2021

Preamble:

OPG stated that it expects to receive a shareholder equity injection from the Province of Ontario totalling $5 billion over the 2025-2027 period. However, OEB staff notes that this $5 billion injection is not discussed in OPG's expert report titled "Common Equity Ratio Study", authored by Concentric.

OPG stated that equity injections directly reduce OPG's borrowing requirements and benefit ratepayers by helping to ensure cost effective financing for OPG's investments in the electricity system. OPG also stated that under the anticipated terms of the equity injection, associated dividends would be in-kind during the business plan period.

In the current proceeding, OPG is requesting a capital structure of 52% equity and 48% debt. In the last payments proceeding, the Parties agreed for the capital structure to remain unchanged from EB-2016-0152 (OPG's previous payments proceeding) at 45% equity and 55% debt for the purposes of determining the nuclear revenue requirements for the 2022-2026 period.

OEB staff notes below that some of the questions are directed to Concentric.

Question(s):

a) Please explain why a shareholder equity injection from the Province of Ontario totalling $5 billion over the 2025-2027 period is required, other than reducing OPG's borrowing requirements.

b) Concentric: Please explain why the $5 billion injection is not discussed in OPG's expert report titled "Common Equity Ratio Study", authored by Concentric.

c) Concentric: Please provide Concentric's views on this $5 billion injection matter.

d) Please explain whether the $5 billion injection (which will dilute the existing shareholders' equity) is a key driver behind the requested 52% equity thickness, an increase from the current OEB-approved 45% equity thickness. OEB staff did not see the $5 billion injection being listed as a key driver in OPG's evidence.

Response

a) While the Application notes that that the shareholder equity injection in OPG will reduce OPG's borrowing requirements, it does not indicate that it is required. The shareholder equity injection is decided upon by the Province of Ontario, as OPG's sole shareholder.

The responses to b) and c) were prepared by Concentric Energy Advisors ("Concentric")

b) Concentric's report examines OPG's deemed capital structure and whether it meets the fair return standard. In doing so, the report focuses on an internal assessment of OPG's business and financial risks and a market/industry assessment regarding trends in the electricity industry and a peer group analysis. Because OPG's revenue requirements reflect a deemed, rather than actual, equity ratio, its actual capitalization, including additional equity and debt funding, does not change the regulatory capital structure being analyzed in Concentric's report.

c) Decisions regarding the structure, timing, and magnitude of shareholder funding, including equity injections, fall outside the scope of Concentric's report and were therefore not evaluated or relied upon in formulating Concentric's recommendation. Concentric's equity ratio recommendation for OPG does not change as a result of the equity injection, because it is based on an analysis of current peer group data and Concentric's assessment that OPG's risks have increased since the time of prior payment amount applications. Further, the recommendation balances considerations related to OPG's heightened risk profile and proxy group position with the OEB's findings in EB-2016-0152 and EB-2024-0063, as discussed in Concentric's report.

d) No, the shareholder equity injection in OPG is not a key driver behind the requested 52% equity thickness for OPG's prescribed facilities. As noted at Ex. C1-1-1, p. 1, lines 16-27, the key driver behind this request is the material increase in OPG's business risks, as supported by the findings in the Concentric report (Ex. C1-1-1, Attachment 1).

For clarity, as the Province of Ontario owns 100% of OPG, the referenced equity injection will not result in a dilution of their ownership.

Board Staff Interrogatory #023

Interrogatory

Reference:
Ref 1: Exhibit A2 / Tab 2 / Schedule 1 / p. 13
Ref 2: Exhibit A2 / Tab 1 / Schedule 1 / Attachment 1 / p. 19
Ref 3: Exhibit C1 / Tab 1 / Schedule 1 / p. 2

Preamble:

OPG stated that its 2025-2031 Business Plan reflects OPG's announced equity partnership with Canada Growth Fund and Building Ontario Fund as minority investors in the Darlington New Nuclear Program (DNNP), which, subject to satisfaction of conditions, is expected to contribute approximately $3 billion of funding.

OPG stated that in October 2025, up to $1 billion from the Building Ontario Fund and up to $2 billion through the Canada Growth Fund have been secured, subject to the satisfaction of certain conditions.

DNNP LP is requesting a capital structure of 100% equity and 0% debt. Section 13.(1) of Ontario Regulation 53/05 establishes the DNNP generator capital structure variance account.

Question(s):

a) Please explain why a shareholder equity injection from the Canada Growth Fund and Building Ontario Fund totalling $3 billion is required.

b) Please explain whether the $3 billion injection (which will dilute the existing partnerships' interests) is a key driver behind the requested 100% equity thickness for the DNNP. OEB staff did not see the $3 billion injection being listed as a key driver in DNNP's evidence.

c) Despite the establishment of the DNNP Generator Capital Structure Variance Account, please explain from a ratepayer perspective why DNNP LP requested capital structure of 100% equity (which earns the OEB's allowed Return on Equity (ROE)) and 0% debt is reasonable, given that based on the OEB's cost of capital parameters set for 2026 rates, the allowed ROE is 9.11% which is much higher than:
   i. The deemed long-term debt rate of 4.73%; and
   ii. The deemed short-term debt rate of 2.72%

d) Despite the establishment of the DNNP Generator Structure Variance Account, please confirm that the partners of DNNP LP are incented to have a higher equity component of the DNNP capital structure than debt component, given the above noted percentage differences in the allowed ROE, deemed long-term debt rate, and deemed short-term debt rate. If this is not the case, please explain.

Response

a) The Canada Growth Fund ("CGF") and the Building Ontario Fund ("BOF") each made a decision to invest equity in DNNP LP, which is effected through the requirements to make equity injections under the respective equity commitment agreements with OPG.

b) No, the CGF and the BOF's equity injections in DNNP LP are not the key drivers behind the requested 100% equity thickness for the DNNP facilities. Informed by the requirements of Section 13(1) of O. Reg. 53/05, the key driver behind this request is the expectation, as discussed at Ex. A1-4-4, Attachment 1, p. 7 for example, that DNNP LP will have an actual capital structure that is 100% equity funded during the first 12-18 months following the in-service date of the first DNNP unit, which, as noted at Ex. C1-1-1, p. 2, line 15 to p. 3, line 1, is supported by Mr. Inskip's testimony (Ex. C1-1-1, Attachment 3).

c) The question references the 2026 cost of capital parameters determined in the OEB's October 31, 2025 letter, and asks the Applicants to ignore the requirements of O. Reg. 53/05 related to DNNP Generator Capital Structure Variance Account ("DGCSVA") in the response. It is impossible to ignore the DGCSVA in this context considering that its purpose is to record the revenue requirement impacts of the differences between the actual capital structure and actual cost of debt issued by DNNP LP and such forecast parameters reflected in the payment amounts.

The deemed long-term debt and short-term debt rates set out in the OEB's October 31, 2025 letter do not factor into the determination of the appropriate capital structure of DNNP LP. As discussed in part b) above, Ex. C1-1-1, Section 2.2 and the testimony of Mr. Cliff Inskip at Ex. C1-1-1, Attachment 3 provide an explanation for why the DNNP LP's requested capital structure is appropriate.

d) The Applicants interpret this question to be asking for confirmation that the partners of DNNP LP are incented to have a higher equity component in DNNP LP's capital structure, ignoring the requirements of O. Reg. 53/05 related to the DGSVA. As is the case with the response to part (c) above, it is impossible to ignore the presence of the DGCSVA in responding to this question. The account ensures that, through the combination of the OEB-approved revenue requirement and any amounts

potentially recorded to the DGCSVA, subject to the OEB's review of the account balance in the manner set out in O. Reg. 53/05, Section 14(2)6, DNNP LP is compensated on the basis of its actual capital structure and actual cost of debt. For clarity, pursuant to Section 13(1) of O. Reg. 53/05, the DGCSVA is effective until the OEB's first payment amount order after the DNNP is completed.

Board Staff Interrogatory #024

Interrogatory

Reference:
Ref 1: Exhibit A2 / Tab 3 / Schedule 1 / Attachment 9

Preamble:

OEB staff notes Moody's June 30, 2025 credit opinion which states the following:

Ontario Power Generation's (OPG) credit profile reflects a Baseline Credit Assessment (BCA) of baa3 with a 3 notch uplift based on its high dependence on and a high probability of extraordinary support from the Province of Ontario (Aa3 stable).

OEB staff notes below that the question below is directed to Concentric.

Question(s):

a) Concentric: OEB staff notes that Concentric considered the latest Moody's report. Please explain how it factored into Concentric's analysis.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Concentric reviewed reports from Moody's as part of its assessment of the business and financial risks of OPG, and how the rating agencies perceive the regulatory environment and business outlook for OPG. In particular, Moody's outlines credit strengths and credit challenges for OPG that could cause a change in OPG's credit rating. In addition, Moody's commented on the importance of the CCR Regulation (as defined in Concentric's report) in terms of OPG being able to maintain sufficient cash flow to support its credit rating during the period of elevated capital expenditures. This information helped inform Concentric's view of OPG's business risk from the perspective of debt investors. While the OEB has previously found that a credit ratings agency's assessment of a utility is not determinative of whether the cost of capital meets equity investors' requirements and the fair return standard,[1] understanding debt investor perspectives can provide evidence regarding the financial integrity component of the Fair Return Standard.

[1] For instance, the OEB previously found in EB-2009-0084 that "[t]he ability of a utility to issue debt capital and maintain a credit rating were generally put forth by stakeholders in the consultation as a sufficient basis upon which to demonstrate that a particular equity cost of capital and deemed utility capital structure meet the capital

With regard to the statement from Moody's cited in the preamble to this interrogatory, Concentric discussed in its report (Ex. C1-1-1, Attachment 1, p. 19) that the OEB has endorsed the stand-alone principle in its findings regarding the deemed capital structure for OPG. For example, the OEB concluded that it would apply the stand-alone principle in establishing the capital structure for OPG, noting that "[t]he stand-alone principle is a long-established regulatory principle,"[2] and that "Provincial ownership will not be a factor to be considered by the Board in establishing capital structure."[3] Concentric further noted that the OEB found the same in EB-2024-0063, where it stated that "the OEB is firmly of the view that the cost of capital should be determined based on the use of funds and the risk profiles of utilities, rather than their ownership type or capital source."[4] As such, while OPG's "high dependence on and a high probability of extraordinary support from the Province" improves OPG's credit profile, such dependence and support are not relevant to the determination of the appropriate regulatory capital structure for OPG.

Concentric also considered in its report (Ex. C1-1-1, Attachment 1, p. 64) that OPG is rated three notches lower than its issuer rating on a stand-alone basis according to S&P and Moody's, which places it toward the low end or below the investment grade credit rating range relative to the proxy group. This higher financial risk profile of OPG supports a finding that its deemed equity ratio should fall at the upper end of the proxy group.

attraction and financial integrity requirements of the FRS. The Board is of the view that utility bond metrics do not speak to the issue of whether a ROE determination meets the requirements of the FRS. The Board acknowledges that equity investors have, as the residual, net claimants of an enterprise, different requirements, and that bond ratings and bond credit metrics serve the explicit needs of bond investors and not necessarily those of equity investors." For example, the OEB previously found in EB-2009-0084 that "[t]he ability of a utility to issue debt capital and maintain a credit rating were generally put forth by stakeholders in the consultation as a sufficient basis upon which to demonstrate that a particular equity cost of capital and deemed utility capital structure meet the capital attraction and financial integrity requirements of the FRS. The Board is of the view that utility bond metrics do not speak to the issue of whether a ROE determination meets the requirements of the FRS. The Board acknowledges that equity investors have, as the residual, net claimants of an enterprise, different requirements, and that bond ratings and bond credit metrics serve the explicit needs of bond investors and not necessarily those of equity investors." (Report of the Board, EB-2009-0084, December 11, 2009, p. 20).

[2] Decision with Reasons, EB-2007-0905, November 3, 2008, p. 140.

[3] *Ibid*., p. 142.

[4] Decision and Order, EB-2024-0063, March 27, 2025, p. 18.

Board Staff Interrogatory #025

Interrogatory

Reference:
Ref 1: Exhibit I1 / Tab 1 / Schedule 1 / Tables 3a & 3b
Ref 2: Exhibit C1 / Tab 1 / Schedule 1 / Tables 1-5

Preamble:

OPG provided the following tables related to revenue deficiencies:
• "Summary of Revenue Deficiency - Regulated Hydroelectric - January 1, 2027 to December 31, 2027"
• "Summary of Revenue Deficiency - OPG Nuclear Facilities - January 1, 2027 to December 31, 2031"

OPG provided the following tables related to cost of capital:

• Summary of Capitalization and Cost of Capital – OPG
  - Calendar Year Ending December 31, 2031
  - Calendar Year Ending December 31, 2030
  - Calendar Year Ending December 31, 2029
  - Calendar Year Ending December 31, 2028
  - Calendar Year Ending December 31, 2027

Question(s):

a) Please provide a table that shows the forecast revenue deficiency for each of 2027 through 2031, as shown in the above tables for hydroelectric and nuclear, along with the forecast revenue deficiency for each of 2027 through 2031, if the common equity component of rate base was maintained at 45% (as opposed to the requested 52% equity ratio in the current application).

Response

a) The requested information is provided in Chart 1 below.

Chart 1 –
Revenue Deficiency Under Proposed Capital Structure and 45% Equity
OPG Regulated Facilities

	2027	2028	2029	2030	2031
Revenue Requirement Deficiency – Regulated Hydroelectric ($M)[1]	243.9	N/A	N/A	N/A	N/A
Hypothetical Revenue Requirement Deficiency at 45% Equity – Regulated Hydroelectric ($M)[2]	195.0	N/A	N/A	N/A	N/A
Revenue Requirement Deficiency – OPG Nuclear Facilities ($M)[3]	1,981.8	1,285.8	1,886.3	1,896.1	2,515.3
Hypothetical Revenue Requirement Deficiency at 45% Equity – OPG Nuclear Facilities ($M)[2]	1,931.3	1,236.1	1,837.9	1,846.6	2,446.6

Notes
[1] Ex. I1-1-1, Table 3a, line 5.
[2] Recalculated using 45% equity.
[3] Ex. I1-1-1, Table 3b, line 5.

Board Staff Interrogatory #026

Interrogatory

Reference:
Ref 1: EB-2020-0290, Decision and Order, November 15, 2021; Settlement Agreement / Exhibit 0 / Tab 1 / Schedule 1 / pp. 15, 23 & 36, July 16, 2021

Preamble:

In the settlement agreement in OPG's last payments proceeding, the following was agreed to by parties:

…In addition to and in consideration of the settlement, the Parties agree that a portion of the nuclear net plant rate base amount (based on in-service capital additions of $358.0M) will be subject to a return on equity equivalent to the OEB-approved long-term debt cost rate for OPG over the period from January 1, 2022 to December 31, 2036. Beginning in 2037, the remaining undepreciated portion of these in-service capital additions will earn a return on equity at the OEB-approved ROE rate in place at that time. The time period over which this approach will apply, as a mitigating measure, coincides with the expected end of the rate smoothing recovery period under O. Reg 53/05, s. 6(2)12.

Question(s):

a) Please confirm that in the current proceeding, OPG included the appropriate portion of the nuclear net plant rate base amount subject to a return on equity (ROE) equivalent to the OEB-approved long-term debt cost rate for OPG over the period from January 1, 2022 to December 31, 2036.

b) If this is not the case, please explain.

Response

a) Confirmed.

b) See above.

Board Staff Interrogatory #027

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Tables 8a, 9a, 10a, 11a, 12a
Ref 2: Exhibit I1 / Tab 1 / Schedule 1 / p. 2
Ref 3: Exhibit H1 / Tab 1 / Schedule 1 / pp. 1 & 50

Preamble:

In Exhibit C, OPG has provided the actual regulated return on equity (ROE) in dollar terms, but not percentage terms for 2020-2024.

In Exhibit I, OPG has provided "Chart 1 – Actual and Forecast ROE" which provide the actual and allowed ROEs in percentage terms.

In Exhibit H, OPG noted that the Earnings Sharing Deferral Account was approved in EB-2020-0290, effective January 1, 2022, to record 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 from January 1, 2022 to December 31, 2026. OPG stated that no entries will be recorded in this account until following the completion of the above five-year period, if applicable. OPG also stated that this account has a zero balance as at December 31, 2024.

Question(s):

a) Please provide the actual regulated ROE (in both dollar terms and percentage terms) and the allowed ROE for each year 2020-2025.

b) Please reconcile the actual regulated ROE in dollar terms in Exhibit C, to the percentage terms in Exhibit I.

c) Please confirm that OPG will be recording entries in the Earnings Sharing Deferral account following the completion of the five-year period ending December 31, 2026, given that in "Chart 1 – Actual and Forecast ROE", OPG has earned more than 100 basis points in actual earnings over the allowed ROEs in percentage terms (in some calendar years). If this is not the case, please explain.

Response

a) Actual regulated ROE in dollars and percentages is provided at Ex. C1-1-1, Tables 8, 9, 10, 11 and 12 (line 5, cols. (c) and (d) in each table). For 2025, the pre-filed evidence provided the same information on a forecast basis at Ex. C1-1-1, Table 7. In Ex. L-I1-Staff-266, Attachment 1 (Confidential), the 2025 preliminary actual ROE information has been provided.

On March 10, 2026, OPG filed minor revisions to its 2022-2024 ROE filings under OPG's Reporting and Record Keeping Requirements that align with the information presented in this Application. These corrections did not have a material impact on reported ROEs and are reflected in the corrected versions of the above noted tables in Ex. C1-1-1.

Chart 1 below summarizes OPG's actual regulated ROE in dollars and percentage terms for 2020-2025, inclusive of the above revisions for 2022-2024 and the preliminary actual results for 2025. For completeness, the 2026 forecast ROE has been added, as found at Ex. I1-1-1, Table 5.

Chart 1 – OPG 2022-2026 Actual / Projected ROE

	2020	2021	2022	2023	2024	2025[1]	2026[2]
Actual ROE ($M)	1,091.8	778.6	907.0	1,082.0	505.1	1,234.1	589.8
Actual ROE (%)	17.4%	10.8%	12.4%	13.7%	5.9%	13.0%	5.6%

[1]The 2025 ROE information has been updated for preliminary 2025 actual results.
[2]The 2026 ROE information is a projection based on the forecasts in the Application.

b) As noted in the response to part a), actual regulated ROE in percentage and dollar terms for 2022-2024 is provided at Ex. C1-1-1, Tables 8-10. In line 5 of each such table, the ROE percentage in col. (c) is equal to the ROE in dollars in col. (d) divided by the deemed equity amount in col. (a). These percentages in col. (c) are in turn intended to be the same as the percentages shown at Ex. I1-1-1, Chart 1. In the course of preparing this response, OPG identified a typographical error in Ex. I1-1-1, Chart 1, for which it will file a correction to the evidence. The corrected chart is provided below for reference, where, for clarity, the 2025 OPG ROE figure is a forecast.

Chart 2 - Actual and Forecast ROE (Corrected Ex. I1-1-1)

	2022	2023	2024	2025	2026	Average
OPG ROE	12.4%	13.7%	5.9%	12.5%	5.6%	10.0%
OEB-approved	8.97%	8.97%	8.93%	8.92%	8.91%	8.94%

c) As described at Reference 3 (Ex. H1-1-1, p. 50), the purpose of the Earnings Sharing Deferral Account is:

> …to record 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 from January 1, 2022 to December 31, 2026. No entries will be recorded in this account until following the completion of the above five-year period, if applicable.

Consistent with the above, OPG will determine whether an entry to the Earnings Sharing Deferral Account is applicable following the conclusion of the 5-year period from January 1, 2022 to December 31, 2026. For clarity, any such entry would be calculated on a cumulative basis over the period, not based on each individual year's performance. Refer to Ex. L-H1-SEC-212 for additional information.

Board Staff Interrogatory #030

Interrogatory

Reference:
Exhibit C1 / Tab 1 / Schedule 2 / pp. 5-7

Preamble:

OEB staff has prepared the following table, summarizing OPG's proposed long-term debt methodology, compared to the historic methodology used in prior applications.

Table 1 – Comparison of Long-Term Debt Updated Methodology versus Historic Methodology

Component	Historic Method in Prior Applications	In Practice	Updated Method in Current Application
Proportions of 10-year and 30-year durations	As Global Insight GoC bond rate forecast was limited to 10-year bonds, a simplifying assumption was made that all planned long-term debt issues would have a tenor of 10 years.	OPG's actual debt issues had been (and continue to be) a combination of 10-year and 30-year tenors.	The forecast has been determined using an equally weighted combination of 10-year and 30-year durations.
Source of Forecast GoC bond rates – 10-year GoC bond tenor for 2025-2027	Global Insight	Actual 10-year GoC yields were different than forecasted yield	Bloomberg Bond Yield Median Forecast (Ticker: BYFC)
Source of Forecast GoC bond rates – 30-year GoC bond tenor for 2025-2027	n/a	Actual 30-year GoC yields were different than forecasted yield	Forward GoC rates from the Bloomberg ticker YCGT0007

Component	Historic Method in Prior Applications	In Practice	Updated Method in Current Application
Source of Forecast GoC bond rates – 10-year GoC bond tenor for 2028-2031 The Bloomberg Bond Yield Median Forecast was not available for 2028-2031	Global Insight	Actual 10-year GoC yields were different than forecasted yield	Forecast inferred by applying the average difference between the Bloomberg Bond Yield Median Forecast and the Bloomberg forward GoC rate for 2026 and 2027, to the Bloomberg forward GoC rate.
Source of Forecast GoC bond rates – 30-year GoC bond tenor for 2028-2031	n/a	Actual 30-year GoC yields were different than forecasted yield	Forward GoC rates from the Bloomberg ticker YCGT0007
Source of Credit Spread	The term-matched credit spread used in the forecast was observed at a point in time, based on quotes from the major banks, when preparing the respective payment amounts application.	Actual credit spreads were different from forecasted credit spread	A three-year historical average of the term-matched credit spread obtained from the six major Canadian banks used as the basis of the forecast.

Question(s):

a) Please confirm that "Table 1 – Comparison of Long-Term Debt Updated Methodology versus Historic Methodology" is accurate. Please update the table as applicable and explain any changes made.

b) Please explain OPG's suggestion that the forecast inferred would be applied to the Bloomberg forward GoC rate. OEB staff is not clear whether this would be a circular

activity, given that the Bloomberg forward GoC rate is also included in the forecast inferred average difference.

Response

a) Not confirmed. OPG has updated OEB staff's Table 1 in Chart 1 below.

As noted in Ex. C1-1-2, p. 5, OPG has not forecasted the cost of planned debt issues for 2025 as there were no remaining forecasted debt issues in 2025.

As noted in Ex. C1-1-2, p. 6, "OPG is utilizing an equally weighted blend of the Bloomberg Bond Yield Median Forecast (Ticker: BYFC) and the forward GoC rates from the Bloomberg ticker YCGT0007, for each of the 10-year and 30-year GoC Bond tenors".

The Bloomberg Bond Yield Median Forecast was not available for 2028-2031 for the 10-year and 30-year GoC bond so the forecast for both was inferred by applying the average difference between the Bloomberg Bond Yield Median Forecast and the Bloomberg forward GoC rate for 2026 and 2027, to the Bloomberg forward GoC rate for the 2028-2031 period.

Chart 1 – Comparison of Long-Term Debt Updated Methodology versus Historic Methodology

Component	Historic Method in Prior Applications	In Practice	Updated Method in Current Application
Proportions of 10-year and 30-year durations	As Global Insight GoC bond rate forecast was limited to 10-year bonds, a simplifying assumption was made that all planned long-term debt issues would have a tenor of 10 years.	OPG's actual debt issues had been (and continue to be) a combination of 10-year and 30-year tenors.	The forecast has been determined using an equally weighted combination of 10-year and 30-year durations.

Component	Historic Method in Prior Applications	In Practice	Updated Method in Current Application
Source of Forecast GoC bond rates – 10-year GoC bond tenor for 2026-2027	Global Insight	Actual 10-year GoC yields were different than forecasted yield	Equally weighted blend of the Bloomberg Bond Yield Median Forecast (Ticker: BYFC) and the Forward GoC rates from the Bloomberg ticker YCGT0007
Source of Forecast GoC bond rates – 30-year GoC bond tenor for 2026-2027	n/a	Actual 30-year GoC yields were different than forecasted yield	Equally weighted blend of the Bloomberg Bond Yield Median Forecast (Ticker: BYFC) and the Forward GoC rates from the Bloomberg ticker YCGT0007
Source of Forecast GoC bond rates – 10-year GoC bond tenor for 2028-2031 The Bloomberg Bond Yield Median Forecast was not available for 2028-2031	Global Insight	Actual 10-year GoC yields were different than forecasted yield	Forecast inferred by applying the average difference between the Bloomberg Bond Yield Median Forecast and the Bloomberg forward GoC rate for 2026 and 2027, to the Bloomberg forward GoC rate for the 2028-2031 period.
Source of Forecast GoC bond rates – 30-year GoC bond tenor for 2028-2031	n/a	Actual 30-year GoC yields were different than forecasted yield	Forecast inferred by applying the average difference between the Bloomberg Bond Yield Median

Component	Historic Method in Prior Applications	In Practice	Updated Method in Current Application
The Bloomberg Bond Yield Median Forecast was not available for 2028-2031			Forecast and the Bloomberg forward GoC rate for 2026 and 2027, to the Bloomberg forward GoC rate for the 2028-2031 period.
Source of Credit Spread	The term-matched credit spread used in the forecast was observed at a point in time, based on quotes from the major banks, when preparing the respective payment amounts application.	Actual credit spreads were different from forecasted credit spread	A three-year historical average of the term-matched credit spread obtained from the six major Canadian banks used as the basis of the forecast.

b) There is no circular activity in the forecasting methodology referenced in the question. For both the 10- and 30-year GoC bond tenors, long-term interest rates for 2026-2027 were determined by blending the Bloomberg Bond Yield Median Forecast and Bloomberg forward GoC rates. As the Bloomberg Bond Yield Median Forecast does not extend to 2028-2031, OPG inferred what the Bloomberg Bond Yield Median Forecast would be so that the methodology of blending both the Bloomberg Bond Yield Median Forecast and Bloomberg forward GoC rates would remain consistent for the IR term.

Board Staff Interrogatory #031

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 2 / pp. 5-7

Preamble:

OPG stated that historically, the term-matched credit spread used in the forecast was observed at a point in time, based on quotes from the major banks, when preparing the respective payment amounts application. In this application, OPG has used a three-year historical average of the term-matched credit spread obtained from the six major Canadian banks as the basis of the forecast.

OPG stated that this improves the forecasting methodology by better capturing a range of market conditions that have materialized in the previous years and could potentially materialize in the future, rather than relying on point-in-time information.

OPG stated that this improves the forecasting methodology by better capturing a range of market conditions that have materialized in the previous years and could potentially materialize in the future, rather than relying on point-in-time information.

Question(s):

a) Please provide support on a high-level basis OPG's historical three-year average data of 135 basis points and 160 basis points, obtained from the six major Canadian banks used as the basis of the forecast.

b) Please explain OPG's statement that its new methodology improves its forecasts, given that both the old methodology and new methodology use data taken at a point-in-time.

Response

a) Refer to Ex. L-C1-CCC-035, part c).

b) OPG has not introduced a "new methodology" for forecasting the cost of its long-term debt. As noted at Ex. C1-1-2, p. 5, lines 15-17, OPG continues to forecast the cost of planned debt issues based on a forecast of Government of Canada bond rates for the applicable tenor and an observed credit spread. OPG has made certain updates and improvements to the methodology and its application, including with

respect to the basis for the observed credit spread, as outlined at Ex. C1-1-2, p. 5, line 19 to p. 6, line 25.

The basis for the observed credit spread used in this Application is an average of the spreads over the last three years. OPG believes that basing the spread on a historical average, rather than relying on a single observation point of one day utilized previously, improves the forecasting accuracy, as a one-day observation is more susceptible to potentially unusual market conditions. While no historical market conditions can precisely predict future market conditions, a historical average approach inherently covers a range of conditions that could be experienced over the IR term and therefore lowers the risk of the credit spread assumption not being representative of such future conditions. For clarity, the Application uses average credit spread information sampled from 1,096 days, compared with just one day in EB-2020-0290.

Board Staff Interrogatory #036

Interrogatory

Reference:
Exhibit C1 / Tab 1 Schedule 3 / pp. 2-3

Preamble:

OPG stated that historically, the corporate spread used in the forecast was observed at a point in time during the preparation of the respective payment amounts application.

In this application, OPG has used an average corporate spread of OPG's 3-month term commercial paper over the Overnight Index Swap (OIS) rate observed since the OIS became the benchmark for commercial paper rates in mid-2024.

OPG noted that the revised approach improves the forecasting methodology by better capturing a range of market conditions that have materialized in the previous months and could potentially materialize in the future, rather than relying on point-in-time information.

OPG stated that the resulting corporate spread is 17 basis points over the OIS rate.

Question(s):

a) Please provide support on a high-level basis of OPG's corporate spread of 17 basis points over the OIS rate.

b) Please explain OPG's statement that its new methodology improves its forecasts, given that both the old methodology and new methodology use data taken at a point-in-time.

Response

a) Refer to Ex. L-C1-CCC-036, part b).

b) OPG has not introduced a "new methodology" for forecasting the cost of its short-term debt. As noted at Ex. C1-1-3, p. 2, lines 8-10, OPG continues to forecast the cost of short-term debt issues based on a forecast of a benchmark "risk-free" rate and an observed credit spread. OPG has made certain updates and improvements to the methodology and its application, including with respect to the basis for the observed corporate spread, as outlined at Ex. C1-1-3, p. 2, line 12 to p. 3, line 5.

Similar to the discussion at Ex. L-C1-Staff-031, part b), with respect to the long-term debt credit spread, the basis for the observed corporate spread is an average of the spreads since the OIS became the benchmark for commercial paper rates in mid-2024. OPG believes that basing the spread on a historical average, rather than relying on a single observation point of one day utilized previously, improves the forecasting accuracy, as a one-day observation is more susceptible to potentially unusual market conditions. While no historical market conditions can precisely predict future market conditions, a historical average approach inherently covers a range of conditions that could be experienced over the IR term and therefore lowers the risk of the corporate spread assumption not being representative of such future conditions.

Board Staff Interrogatory #037

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 3 / pp. 2-3
Ref 2: EB-2020-0290, Exhibit C1 / Tab 1 / Schedule 3 / p. 2, December 31, 2020

Preamble:

OEB staff has prepared the following table, summarizing OPG's proposed short-term debt methodology, compared to the historic methodology used in prior applications.

Table 1 – Comparison of Short-Term Debt Updated Methodology versus Historic Methodology

Component	Historic Method in Prior Applications	In Practice	Updated Method in Current Application
Source of Forecast 3-month T-Bill rate for 2025-2027	Global Insight forecast used as the basis for the bankers' acceptances interest rate forecast after adjusting for the spread differential between bankers' acceptances and the yield on treasury securities.	Actual 3-month bankers' acceptance rates were different than forecasted rate	Equally weighted blend of the 3-month forward Overnight Index Swap (OIS) rates from the Bloomberg ticker YCSW0147 and the Bloomberg Bond Yield Median Forecast (Ticker: BYFC)
Source of Forecast – 3-month T-Bill rate for 2028-2031	Global Insight forecast used as the basis for the bankers' acceptances interest rate	Actual 3-month bankers' acceptance rates were different than forecasted rate	Forecast inferred by applying the average difference between the Bloomberg Bond Yield Median

Component	Historic Method in Prior Applications	In Practice	Updated Method in Current Application
The Bloomberg Bond Yield Median Forecast was not available for 2028-2031	forecast after adjusting for the spread differential between bankers' acceptances and the yield on treasury securities.		Forecast and the Bloomberg forward OIS rate for 2026 and 2027, to the Bloomberg forward OIS rate.
Source of Credit Spread	The corporate spread forecast over the IR term was based on the corporate spread of 5 basis points over the Canadian bankers' acceptances rate at the time of the application.	Actual credit spreads were different from historic forecasted credit spread	An average corporate spread used, based on OPG's 3-month term commercial paper over the OIS rate observed since the OIS became the benchmark for commercial paper rates in mid-2024

Question(s):

a) Please confirm that "Table 1 – Comparison of Short-Term Debt Updated Methodology versus Historic Methodology" is accurate. Please update the table as applicable and explain any changes made.

c) Please explain OPG's suggestion that the forecast inferred would be applied to the Bloomberg forward OIS rate. OEB staff is not clear whether this would be a circular activity, given that the Bloomberg forward OIS rate is also included in the forecast inferred average difference.

Response

a) Not confirmed. OPG has updated OEB staff's Table 1 in Chart 1 below.

Updates include short-term interest rate for 2025 based on actual commercial paper issued in 2025, and the Bloomberg Bond Yield Median Forecast (Ticker: BYFC) being used for the three-month T-Bill rate.

Chart 1 – Comparison of Short-Term Debt Updated Methodology versus Historic Methodology

Component	Historic Method in Prior Applications	In Practice	Updated Method in Current Application
Source of Forecast 3-month T-Bill rate for 2026-2027	Global Insight forecast used as the basis for the bankers' acceptances interest rate forecast after adjusting for the spread differential between bankers' acceptances and the yield on treasury securities.	Actual 3-month bankers' acceptance rates were different than forecasted rate	Equally weighted blend of the 3-month forward Overnight Index Swap (OIS) rates from the Bloomberg ticker YCSW0147 and the Bloomberg Bond Yield Median Forecast (Ticker: BYFC) for the 3-month T-Bill rate
Source of Forecast – 3-month T-Bill rate for 2028-2031 The Bloomberg Bond Yield Median Forecast was not available for 2028-2031	Global Insight forecast used as the basis for the bankers' acceptances interest rate forecast after adjusting for the spread differential between bankers' acceptances and the yield on treasury securities.	Actual 3-month bankers' acceptance rates were different than forecasted rate Bloomberg forward OIS rate for 2026 and 2027, to the Bloomberg forward OIS rate.	Forecast inferred by applying the average difference between the Bloomberg Bond Yield Median Forecast and the Bloomberg forward OIS rate for 2026 and 2027, to the Bloomberg forward OIS rate.
Source of Credit Spread	The corporate spread forecast over the IR term was based on the corporate spread of 5 basis points over	Actual credit spreads were different from historic forecasted credit spread	An average corporate spread used, based on OPG's 3-month term commercial paper over the OIS

Component	Historic Method in Prior Applications	In Practice	Updated Method in Current Application
	the Canadian bankers' acceptances rate at the time of the application.		rate observed since the OIS became the benchmark for commercial paper rates in mid-2024

c) There is no circular activity in the forecasting methodology referenced in the question. Similar to Ex. L-C1-Staff-030, the short-term debt rates for 2026-2027 were determined by blending the Bloomberg Bond Yield Median Forecast for the three-month T-Bill rate and Bloomberg three-month forward OIS rates. As the Bloomberg Bond Yield Median Forecast does not extend to 2028-2031, OPG inferred what the Bloomberg Bond Yield Median Forecast would be so that the methodology of blending both the Bloomberg Bond Yield Median Forecast and Bloomberg forward OIS rates would remain consistent for the IR term.

Board Staff Interrogatory #038

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Tables 1 – 6
Ref 2: Exhibit C1 / Tab 1 / Schedule 3 / p. 2

Preamble:

OEB staff has prepared the following table, summarizing OPG's proposed short-term debt rate requests, which were derived using OPG's current methodology (versus the methodologies used in prior applications).

Table 1 – Summary of OPG's Proposed Short-Term Debt Rates

Year	Proposed Short-Term Debt Rate
2026	2.47%
2027	2.79%
2028	2.93%
2029	3.07%
2030	3.22%
2031	3.39%

In a footnote, OPG suggested that the Bloomberg data incorporated into the above-noted proposed short-term debt rates were obtained on November 21, 2025.

Question(s):

a) Please confirm that "Table 1 – Summary of OPG's Proposed Short-Term Debt Rates" is accurate.

b) If this is not the case, please update "Table 1 – Summary of OPG's Proposed Short-Term Debt Rates" and explain any changes made.

c) Please update "Table 1 – Summary of OPG's Proposed Short-Term Debt Rates" using OPG's methodology from its last payments proceeding (by adding a new column) and summarize the assumptions made to derive these short-term debt rates. Please perform this task to the best of OPG's ability, given that bankers acceptances have been phased out.

d) With the results of part c), please re-run the proposed revenue requirements for 2027-2031 using the old methodology.

Response

a) and b)

Confirmed, therefore no changes needed.

c) and d)

The methodology from the last payment proceeding "used the Global Insight forecast as the basis for the bankers' acceptances interest rate forecast after adjusting for the spread differential between bankers' acceptances and the yield on treasury securities" (EB-2020-0290, Ex. C1-1-3, p. 2). As OEB staff have noted, banker's acceptances have been phased out. As well, since the Canadian Dollar Offered Rate ("CDOR"), which was the benchmark rate for banker's acceptances, is no longer published, there is no suitable alternative to calculate the banker's acceptances interest rate. As such, OPG is unable to perform the requested analysis.

Board Staff Interrogatory #039

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / p. 2
Ref 2: Exhibit H1 / Tab 1 / Schedule 1 / pp. 58 & 72
Ref 3: Exhibit A1 / Tab 4 / Schedule 4 / pp. 6-7
Ref 2: EB-2024-0063, OEB Cost of Capital Generic Proceeding, Decision and Order, March 27, 2025, pp. 95-96

Preamble:

OPG noted that Section 13(1) of Ontario Regulation 53/05 establishes the Darlington New Nuclear Program (DNNP) generator capital structure variance account (DGCSVA) which requires the OEB to provide, using this variance account, the recovery of the revenue requirement impacts arising from DNNP LP's actual capital structure and cost of debt, subject to such debt having been prudently incurred. OPG proposes an effective date of January 1, 2026.

O. Reg. 53/05 states:

> 13. (1) The DNNP generator shall establish a variance account in connection with section 78.1 of the Act that, until the effective date of the first DNNP post-construction payment order, records differences between,
>
> (a) the revenue requirement impacts arising from the DNNP generator's capital structure cost of debt reflecting the actual amount and cost of borrowing issued by it; and
>
> (b) the amount of the revenue requirement impacts arising from the capital structure and the cost of debt that were included in payments made under section 78.1 of the Act to the DNNP generator. O. Reg. 315/25, s. 12.
>
> (2) The account shall not include any amount included in a variance account established under subsection 11(1) or 12(1). O. Reg. 315/25, s. 12.
>
> (3) The DNNP generator shall record interest on the balance of the account as the Board may direct. O. Reg. 315/25, s. 12.

OPG stated that the manner in which the account entries are calculated needs to consider the interaction with the Darlington New Nuclear Project Variance Account re Development (DNNPVARD). The DNNPVARD will record the revenue requirement impact of differences between actual and forecast capital costs for the DNNP (i.e., measured as the difference between the actual and forecast rate base values) using the forecast cost of capital parameters approved by the OEB.

For the DGCSVA, OPG proposes that the revenue requirement impacts arising from:

- The amount for s. 13(1)(a) above be calculated by applying a debt component (and interest cost) equal to the actual amount of DNNP LP's debt outstanding (and interest cost) at the time to the actual rate base value (i.e., the dame actual rate base value used in the DNNPVARD variance calculation), with the remaining portion of such actual rate base value representing the equity component.
- The amount for s. 13(1)(b) above would be calculated by applying the forecast cost of capital parameters (including percentage capital structure) approved by the OEB to the actual rate base value.

Question(s):

a) Please explain why the DNNPVARD will capture impacts relating to the OEB-approved rate base value (i.e. forecasted rate base), but s. 13(1)(b) above will capture impacts relating to the actual rate base value.

b) Please explain why an effective date of January 1, 2026 is appropriate, given the payment amounts are proposed to be effective January 1, 2027.

c) Please explain whether simple interest will be calculated on the opening monthly balance of the DGCSVA, using the OEB-approved EB-2024-0063 interest rate methodology, as per the OEB's generic proceeding on Cost of Capital, further to what is stated by OPG in "Section 9.0 Interest) of Exhibit H.

Response

a) As discussed in Ex. H1-1-1, Section 6.1, among other items, the DNNPVARD is to record the revenue requirement impacts arising from differences in costs incurred by DNNP LP – whether capital or non-capital – for the DNNP, in relation to corresponding forecasts underpinning an approved revenue requirement. With respect to capital costs, such impacts would be measured with reference to rate base, consistent with how these costs are recovered in a revenue requirement. This requires a comparison of the actual rate base value to the OEB-approved forecast rate base value. As the scope of the DNNPVARD does not capture differences

between forecast and actual cost of capital parameters, such amounts would need to be recorded in the account while holding constant the forecast cost of capital parameters reflected in the approved revenue requirement (including capital structure and cost of debt).

As discussed in Ex. H1-1-1, Section 6.2, the DGCSVA is to record the differences between the revenue requirement impacts arising from a capital structure and cost of debt based on the amount and cost of borrowing incurred by DNNP LP, and the corresponding forecasts reflected in the OEB-approved payment amounts. These impacts need to be measured with reference to rate base, consistent with how cost of capital amounts are recovered in a revenue requirement. As the scope of the DGSVA does not capture differences between the forecast and actual rate base values, such amounts would need to be recorded in the account while holding constant a rate base value. For clarity, the DGCSVA does not record any impacts of changes in the OEB-authorized return on equity rate.

The Applicants propose that the actual rate base be used for the purpose of the DGCSVA entries, as this would allow for the combination of the DNNPVARD and the DGCSVA to accurately “true up” the revenue requirement impacts for the overall difference in respect of capital costs, capital structure and cost of debt relative to the approved payment amounts. Said differently, this approach would achieve the same outcome as if all these actual parameters were known at the time the original revenue requirement was set. The Applicants believe that this is an appropriate result and is consistent with the purpose of these accounts. Using an example, Charts 1-3 below illustrate how this approach to the DNNPVARD and the DGCSVA would reflect the overall difference in the revenue requirement impacts arising from the combined factors covered by these accounts.

In contrast, if a forecast rate base value were to be used for purposes of the DGCSVA entries, this would create a recovery windfall or shortfall relative to the actual variances experienced by DNNP LP.

Chart 1 – Illustrative Revenue Requirement Calculation of Changes to DNNP Facilities' Capital Costs, Capital Structure and Cost of Debt ($M)

Line	Particulars	Approved Forecast	Actual	Overall Difference
		(a)	(b)	(c) = (b) – (a)
1	DNNP Net Plant Rate Base Amount	6,585.0	6,000.0	(585.0)
2	Capitalization – Debt	0.0%	50.0%	
3	Capitalization – Equity	100.0%	50.0%	
4	Cost Rate – Debt	5.0%	6.0%	
5	Cost Rate – Return on Equity *(not trued up)*	9.0%	9.0%	
6	Weighted Average Cost of Capital (line 2 x line 4 + line 3 x line 5)	9.0%	7.5%	
7	Cost of Capital (line 1 x line 6)	592.7	450.0	(142.7)
8	Depreciation[1]	109.8	100.0	(9.8)
9	**Revenue Requirement Impact[2]** (line 7 + line 8)	**702.4**	**550.0**	**(152.4)**

[1] Based on an assumed service life of 60 years.
[2] For simplicity, these illustrative revenue requirement calculations exclude income tax impacts that would otherwise be captured in the accounts.

Chart 2 – Illustrative Amounts Recorded to DNNPVARD ($M)

Line	Particulars	Account Entry
		(c)
10	DNNP Net Plant Rate Base Amount (line 1, col. (c))	(585.0)
11	Weighted Average Cost of Capital (line 6, col. (a))	9.0%
12	Cost of Capital (line 10 x line 11)	(52.7)
13	Depreciation[1] (line 8, col. (c))	(9.8)
14	**Revenue Requirement Impact – Entry Recorded to DNNPVARD[2]** (line 12 + line 13)	**(62.4)**

[1] Based on an assumed service life of 60 years.
[2] For simplicity, these illustrative revenue requirement calculations exclude income tax impacts that would otherwise be captured in the accounts.

Chart 3 – Illustrative Amounts Recorded to DGCSVA ($M)

Line	Particulars	Approved Forecast Capital Structure and Cost of Debt[2]	Actual Capital Structure and Cost of Debt[3]	Account Entry
		(a)	(b)	(c) = (b) – (a)
15	DNNP Net Plant Rate Base Amount (line 1, col. (b))	6,000.0	6,000.0	
16	Weighted Average Cost of Capital (line 6, cols. (a) and (b))	9.0%	7.5%	
17	Cost of Capital (line 15 x line 16)	540.0	450.0	
18	**Revenue Requirement Impact – Entry Recorded to DGCSVA[1]**	**540.0**	**450.0**	**(90.0)**
19	**Combined Revenue Requirement Impact – DNNPVARD and DGCSVA** (line 14, col. (c) + line 18)			**(152.4)**

[1] For simplicity, these illustrative revenue requirement calculations exclude income tax impacts that would otherwise be captured in the accounts.
[2] Col. (a), lines 20-24 from Chart 1, col. (a), lines 2-6.
[3] Col. (b), lines 20-24 from Chart 1, col. (b), lines 2-6.

b) The effective date of January 1, 2026 for both the DNNPVARD and the DGCSVA is set by O. Reg. 53/05.[1] As the rate base value for the DNNP facilities is expected to be zero for 2026, no entries are expected to be recorded in the DGCSVA in 2026.[2]

c) The Applicants confirm that they have proposed that simple interest be calculated on the opening monthly balance of the DGCSVA using the OEB-determined prescribed interest rates derived by the approach described in section 3.7.1 of the EB-2024-0063 Decision and Order dated March 27, 2025.

[1] Subject to the satisfaction of conditions set out in in O. Reg. 53/05 section 8.
[2] As discussed in Ex. L-H1-01-Staff-247, Concurrent Cost Recovery interest amounts are not recorded in the DGCSVA.

Board Staff Interrogatory #040

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 49

Preamble:

Concentric provided in its report "Figure 10: Pro Forma Regulated-Only Credit Metrics". This figure provides the pro forma regulated-only FFO/Debt and CFO/Debt metrics over the IR Term at OPG's current equity thickness of 45.0% and at Concentric's recommended equity thickness of 52.0%. The years 2027-2031 are shown in this table.

OEB staff notes below that the questions are directed to Concentric.

Question(s):

a) Concentric: Please provide the assumptions used to generate Figure 10.
b) Concentric: Please explain whether the availability of 2025 fiscal year data would change the metrics shown in Figure 10.
c) Concentric: If yes, please update Figure 10, including describing the assumptions used.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Please see Concentric's Exhibit 1, pages 1 and 2 (Ex. C1-1-1, Attachment 1, pp. 101-102) for the calculations and corresponding footnotes describing the development of the data in Figure 10. Concentric is additionally providing these calculations in Excel format as Attachment 1.

   For clarity, as described in Concentric's report (Ex. C1-1-1, Attachment 1, p. 48), Figure 10 reflects a *pro forma* forecast of credit metrics for OPG's regulated assets only, based on its deemed capital structure. That analysis aligns with credit rating agencies' methodologies and focuses on the metrics emphasized by the rating agencies as indicated by discussions in their rating reports (i.e., Funds From Operations to Debt, or "FFO/Debt," for S&P and Cashflow from Operations to Debt, or "CFO/Debt," for Moody's). These estimated metrics, as calculated by Concentric on such *pro forma* basis, reflect different measures of cash flow expressed as a percentage of long-term debt, based on a hypothetical/deemed capital structure for the regulated business, excluding the DNNP. As such, the *pro forma* metrics

provide a reasonable representation of financial flexibility and credit strength for the purposes of evaluating an appropriate capital structure for rate-setting purposes.

To summarize the assumptions used to generate Figure 10:

- The analysis estimates cash flow metrics based on the after-tax return on rate base at different equity ratios, adjusted for items that impact cash flow.
- Inputs to the calculations such as rate base, cost of debt, income taxes, depreciation, adjustments for other items impacting cashflow from operations (including pension/OPEB and nuclear liability related expenses and expenditures), pension & OPEB liabilities, and the pension & OPEB allocation are sourced from the OPG Exhibits in this Application as identified in the "Formula/Source" column. The formulas used to calculate various items in the analysis are also described in that column.
- A return on equity of 9.11% is assumed throughout the analysis period.
- Amounts do not reflect OPG's payment amounts shaping proposal in this Application or the availability of Clean Electricity Investment Tax Credits.
- Although a decrease from OPG's proposed equity thickness of 52% could negatively impact the cost of debt (for instance, by reducing cash flows that debt investors evaluate in their assessments of credit risk), conservatively, no assumption of such impact has been reflected in this analysis.
- As OPG's pension and OPEB liabilities are not segregated for ratemaking purposes, an allocation factor was applied to allocate a portion of OPG's pension and OPEB liabilities to the prescribed facilities consistent with the factor used to allocate OPG's pension & OPEB costs to the prescribed facilities for ratemaking purposes.

b) The analysis reflects forecasted pro forma credit metrics for the period 2027 to 2031, based on as-filed inputs from this Application. As such, changes in the 2025 fiscal year data do not affect the analysis.

c) Not applicable.

Board Staff Interrogatory #041

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 3 / pp. 5-7; 13-14; 33

Preamble:

Polar Star stated the in-service date for Unit 1 is expected to be October 2030, after which the special purpose vehicle (SPV) will seek to raise investment grade non-recourse debt in the capital markets as soon as practicable.

Polar Star stated that issuing a bond for a first-time issuer such as the SPV requires extensive preparation, which is expected to take at least 6-9 months after Unit 1 comes into service.

Polar Star noted that there may also be advantages for the SPV to defer the first bond issuance to potentially obtain better terms for the financing based on a longer operating history.

Polar Star stated that the specific length of operating history will depend on what happens during the months following the in-service date including: (i) the number, duration and reason for any unplanned outages; and (ii) actual versus forecast electricity generation levels.

Polar Star stated that its estimated minimum 6–9-month period is the actual time to obtain credit ratings, negotiate documentation, market and issue a bond. However, it doesn't incorporate the longer period that is very likely require to observe Unit 1 in operation to partially mitigate first of a kind (FOAK) risk and thus enable a successful offering. It also does not take into account that the SPV may strategically decide to defer the offering by some months or a year-plus to secure better terms.

Polar Star concluded that the limited spread upside for a bond holder relative to risk and the unquantifiable magnitude of the FOAK risks will make if very challenging to issue non-recourse investment grade bonds within 12-18months of the in-service date of Unit 1 In Polar Star's view, there is a low to very low probability of a successful offering of these bonds within 12-18 months following the in-service date of the first SMR unit for the DNNP.

OEB staff notes below that some of the questions are directed to Polar Star.

Question(s):

a) Please explain whether the in-service date for Unit 1 is still expected to be October 2030. If this is not the case, please explain.

b) Polar Star: Please provide an update (if any) on timing of raising investment grade non-recourse debt since the application was filed.

c) Polar Star: Please explain whether the first issuance is expected to take 6-9 months after Unit 1 comes into service, or within 12-18 months, or may be "strategically" deferred even further.

d) Polar Star: Please explain what time period Polar Star is suggesting regarding the deferral of the first bond issuance "based on a longer operating history."

e) Polar Star: Please explain why Polar Star has highlighted operating history risks regarding DNNP unplanned outages and electricity generation levels when OPG in general is faced with these risks. Please confirm that it is due to FOAK technology. If this is not the case, please explain.

Response

a) *OPG Response:* The expected in-service date for DNNP Unit 1 continues to be October 2030.

Parts b)-e) of this response was prepared by Polar Star Advisory Services ("Polar Star")

b) In my testimony, I concluded that there was a low to very low probability of a successful non-recourse bond offering within 12-18 months after the in-service date. There is no update since the Application was filed.

c) and d)

In my testimony, I did not opine on a specific time period when the first bond issue could be undertaken. I concluded that that there was a low to very low probability of a successful non-recourse bond offering within 12-18 months after the in-service date of Unit 1. The actual timing of such first issuance will be dependent on the circumstances at the time (such as, but not limited to, the operational history of Unit 1 since the in-service date, general market developments on this SMR technology and/or capital markets conditions) which would need to be reviewed to determine their impact on the time for the issuance. If, for example, (i) there are operational

issues that have not been satisfactorily addressed or (ii) credit rating agencies need a longer period for their assessment or (iii) capital markets are unfavourable, it may be necessary to wait until such matters are resolved before undertaking an inaugural bond offering.

The 6-9 months timeframe in my testimony refers to my expectation of the actual time that would be involved to obtain credit ratings, structure and negotiate a trust indenture, finalize independent reports, obtain legal opinions, undertake investor marketing activities nationally and price and issue the bonds. This timeframe is a measure of the typical estimated time to issue a bond if there are no other constraints (such as FOAK technology risk in the case of DNNP which I expect to result in a period longer than 6-9 months from the Unit 1 in-service date for a successful first bond issuance).

e) I highlighted operating history risks regarding DNNP unplanned outages and electricity generation levels as bond investors will assess operating performance to be satisfied that the SMR can generate stable and predictable cashflows to service any potential debt. I confirm that I highlighted operating risks primarily due to FOAK nuclear technology risk.

Board Staff Interrogatory #042

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 3 / p. 31

Preamble:

Polar Star noted that there are about 50 utilities, infrastructure, energy infrastructure, and power generation bond issuers in Canada with broadly marketed investment grade bonds outstanding, where credit spreads are regularly tracked and broadly communicated to investors.

Polar Star provided Table III, Canadian Investment Grade Utility Issuers (~50 issuers), which show the highest and lowest credit spreads for these bond issuers as of mid-October 2025, also including OPG bonds.

Polar Star assumed that the special purpose vehicle (SPV) 10-year debt (the longest maturity most likely available in an initial offering) could be priced with a spread 20% higher than the highest spread from the ~50 issuers.

Polar Star stated that the incentive for SPV debt investors is at most ~1% per annum relative to buying OPG bonds. Polar Star noted that given this overall limited potential upside, potential bond investors are very unlikely to be willing to take any unusual risks.

OEB staff notes below that the questions are directed to Polar Star.

Question(s):

a) Polar Star: Please explain how the following were calculated at a high level:
   i. The 20% higher spread
   ii. The 1% per annum incentive

b) Polar Star: Please explain if the SPV (i.e., DNNP) debt could be structured to provide more potential upside to potential bond investors, but also reducing costs to DNNP ratepayers.

Response

This response was prepared by Polar Star Advisory Services ("Polar Star")

a) For clarity, the 20% higher spread relative to the highest spread among the approximately 50 bond issuers as referenced in my testimony is not intended to suggest that a DNNP LP bond would be priced at such level. Rather, the 20% higher spread is an order of magnitude assumption, based on my professional judgment, of a reasonable spread beyond which pricing might no longer be broadly perceived to be consistent with an investment grade infrastructure credit with a favourable period of operation. The approximate 1% per annum premium relative to buying OPG bonds was calculated by taking the highest 10-year investment grade credit spread (~170 bps) from the referenced group of approximately 50 bond issuers, multiplying it by 1.2 and then subtracting the estimated OPG credit spread. From this I concluded that:

> *"Given this overall limited potential upside, potential bond investors are very unlikely to be willing to take any unusual risks such as unquantifiable FOAK nuclear risk on an SMR within 12-18 months of the in-service date of the first SMR unit."* (Ex. C1-1-1, Attachment 3, pp. 31-32)

As noted above, this order of magnitude commentary is not intended to be a forecast of DNNP LP bond pricing but rather to demonstrate that investment grade bond pricing (which assumes an offering after a period of stable and favourable operations sufficient to address the FOAK nuclear technology risk, satisfactory independent reports, and two investment grade credit ratings) does not compensate investors for FOAK nuclear technology risk.

b) I interpret this question to be in relation to DNNP LP issuing a non-recourse investment grade bond within 12-18 months of the Unit 1 in-service date. While a higher credit spread would be viewed favourably by potential bond investors, in my opinion, any reasonable credit spread consistent with an investment grade infrastructure credit would not be sufficiently attractive to offset nuclear FOAK technology risk concerns during the first 12-18 months of the Unit 1 in-service date. Bond investors in Canada, particularly the larger ones, will do a detailed credit analysis of the issuer and the project and, in my opinion, most investors who invest in investment grade infrastructure bonds will be unwilling to accept FOAK technology risk in exchange for any reasonable higher investment grade return.

Additionally, even if sub-investment grade bonds with a higher interest rate and possibly more stringent terms and conditions could be issued within 12-18 months of the Unit 1 in-service date, in my opinion it is too speculative at this stage to conclude that this approach would reduce costs to DNNP LP's ratepayers. Examples of uncertainties include:

- What interest rate might be sufficient to offset FOAK technology risk for sub-investment grade debt investors and would it be less than OEB's authorized equity return and, if so, by how much?
- What amount of sub-investment grade bonds could be issued and is the size sufficient to be the basis on which to build a financing strategy?
- How soon after the Unit 1 in-service date could the bonds be issued considering normal bond issuance preparation and due diligence?
- How long would the sub-investment grade bonds be outstanding? At what point would they take the place of lower cost investment grade bonds?
- What would be the net cost or benefit of higher interest rate sub-investment grade bonds being outstanding beyond the point at which DNNP LP could issue investment grade debt?
- What would be the impact of an initial sub-investment grade offering on DNNP LP's longer term borrowing program?

Based on almost two decades of marketing bond offerings for first time issuers, I believe that it would be better for ratepayers if DNNP LP demonstrated a satisfactory period of successful operations and then approached the markets for investment grade debt. A successful first issue is foundational for all future issues. If waiting to complete a satisfactory operating period to help ensure a successful investment grade non-recourse inaugural bond offering results in a higher cost of capital during, for example, some portion of the first 12-18 months after the Unit 1 in-service date (taking into account that it is expected to take 6-9 months to just put the financing in place) this is, in my opinion, the cost DNNP ratepayers should bear so as to benefit from a future successful bond offering program. I therefore do not think DNNP ratepayers would benefit from DNNP LP trying to structure a higher cost transaction that might permit going to the debt market earlier, assuming it is even possible.

Board Staff Interrogatory #043

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 3 / pp. 5 & 6

Preamble:

Polar Star stated the following:

> The in-service date for Unit 1 is expected to be October 2030, after which the SPV will seek to raise investment grade non-recourse debt in the capital markets as soon as practicable.

OEB staff notes below that some of the questions are directed to Polar Star

Question(s):

a) Polar Star: What forms of debt financing, if any, could be available to DNNP LP other than non-recourse debt?

b) Polar Star: What determines when investment grade debt issuances are "practicable"?

c) Polar Star: Please explain whether other forms of debt financing could be raised sooner than "investment grade non-recourse debt" and whether the terms would typically be more or less favourable.

Response

This response was prepared by Polar Star Advisory Services ("Polar Star")

a) I do not have the necessary information regarding the appetite of the parties that might play a role in the financing of DNNP, and I was not engaged to perform such an analysis. Generically forms of financing that could theoretically be available to a project developer (in the right circumstances) other than non-recourse debt include:
   - **External Guarantees:** Financing that is guaranteed by a creditworthy government such as the Canadian Federal Government or a provincial government. An example would be the Muskrat Falls Projects in Newfoundland

and Labrador where the Government of Canada guaranteed approximately $7.9 billion of debt for affiliates of Nalcor Energy and Emera Inc.

- **Off Taker Support Agreements:** Financing that is supported by undertakings from a project off taker (e.g., a contract where payments are structured to improve the credit profile of the project and make it more financeable or reduce debt costs). An example would be the ~$10 billion Northwest Redwater Refinery project in Alberta where the two investment-grade off takers (purchasers of refined products) agreed to make certain payments starting on a fixed date, whether or not the project was completed or the expected output was delivered. Another example would be where a utility is paid a price for power that has a fixed and variable component and where the fixed component is designed to cover operating and debt service costs and the variable component is designed to provide a return on and return of equity.
- **Pooled Assets:** Financing that is supported by a pool of assets so that if any individual asset fails to perform as required, cash flows from other assets are available to service the debt. An example would be a pool of unrelated real estate assets that are financed as a package.
- **Corporate Financing:** A corporate financing where a corporation raises debt based on the credit strength of its full business and uses the debt proceeds to finance a particular asset or project (or where such party provides a guarantee to an affiliate raising the debt). This would normally only apply if the corporation owned 100% of the asset as a corporation would typically not want to use its balance sheet to support third party owners. For example, BC Hydro financed the 100% owned Site C hydroelectric project using its corporate balance sheet and OPG financed its 100% owned Darlington Refurbishment Project on balance sheet.

b) Factors impacting the timing of accessing the debt market following completion of a project could include but are not necessarily limited to:

- The type of project that is being financed (the degree of complexity, risk profile, previous financings and investor experience with similar projects, etc.)
- Whether there is a satisfactory period of observable operational success and cash generation following the in-service date
- Availability of satisfactory reports from independent third parties (on operations, supply chain, product markets, etc.)
- General developments in the industry at the time of going to market (for DNNP this would mean deployment of SMRs with the same or very similar technology)
- Whether credit rating agencies are prepared to provide credit ratings that are not adversely affected because of outstanding concerns that might be addressed over the short term through additional information including observing operations
- Whether a satisfactory borrowing platform has been negotiated and finalized

- Whether favourable conditions exist in the capital markets (for example, there can be times when access is constrained, particularly for inaugural issuers, depending on market conditions)

c) At a high level, debt investors do not accept risks that they expect should be borne by equity investors. In my opinion, the FOAK technology risk associated with the SMRs is not a risk that most debt investors in Canada would accept until they are reasonably satisfied that the risk is acceptable as evidenced by a period of satisfactory operations and satisfactory independent reports.

If credit enhancements of the types referred to in part a) of this question were available, debt financing could very likely be raised sooner than "investment grade non-recourse debt." The terms would be based, in part, on the creditworthiness of the counterparty backing the debt (i.e., the external guarantor, off-take support provider, asset pool or corporation/guarantor with a wholly owned asset). To determine whether the terms of such an arrangement are more or less favourable than investment grade non-recourse debt would require analyzing and aggregating the cost and impact of a particular credit enhancement and comparing with the non-credit enhanced debt. A rational issuer would only utilize any available credit enhancement if the aggregate cost and impact of the credit enhanced debt is favourable compared to that of the non-credit enhanced debt. It is not possible to generalize the outcome of such an analysis. However, an example of where the outcome could be determined as more favourable is where a government or government agency (e.g., Federal Government Guarantee of debt of Muskrat Falls project in NL) provides a loan guarantee that permits the issuance of debt at below the rates that would apply to debt financed on the strength of the project alone.

Board Staff Interrogatory #044

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 3 / pp. 9, 18, and 19

Preamble:

Polar Star stated the following:

Importantly, all four SMRs are expected to be within a common SPV financing framework and there will be interaction risks between the various SMR units, with bond investors likely having at least some risk exposure to all units that are approved and constructed…

…As Units 2, 3 and 4 come online, diversification will increase, resulting in reduced concentration risk to bondholders, although multiple SMR units could be susceptible to experiencing the same problems/defects (but most likely at different times given different in-service dates). On the other hand, any challenges associated with the first unit operations may well be addressed prior to the completion of Units 2, 3 or 4. Overall, while there is a limit to the benefit of diversification for identical assets, the risk is clearly greatest when there is only one unit in operation."

OEB staff notes below that the questions are directed to Polar Star.

Question(s):

a) Polar Star: The report refers to interaction risks (p. 9) associated with the construction of multiple small modular reactors (SMR) units, as well as risk reduction from having multiple plants (p. 18-19). What is the net effect on risk of these countervailing risks?

Response

This response was prepared by Polar Star Advisory Services ("Polar Star")

a) The net effect on risk associated with having multiple reactors as part of the DNNP is complex to assess and varies over time.

   The period of greatest risk for a bond investor is immediately following the issuance of the first bond sometime following the in-service date of the first Unit. At this stage,

bond investors are wholly reliant on the cash flows from the first Unit. If the first Unit fails to operate satisfactorily there will be no cash flow generated to cover debt service costs. At this stage, there are likely to be other reactors in various stages of development or construction. Even if Unit 1 is successfully operating, there is some (difficult to assess and quantify) risk that problems associated with other units under development or construction could interfere with the cash flow stream from Unit 1. There is no diversification benefit at this stage but there is interface risk between the operating Unit and the Units under construction, so the net effect is that this is the riskiest stage for a bond investor.

At a later stage when all units are completed and assuming there has been a period of successful operations for multiple units, there is likely to be a net diversification benefit of having multiple units (assuming no intrinsic defects in the SMRs). If a unit is not operating, bond investors can look to cash flow generated from other operating units. This is likely to be the least risky stage for a bond investor due to the risk diversification benefit.

Generally speaking, the more mature the asset and the lower the technological risk, the greater is the likelihood that multiple units will result in diversification. The greater the technological risk (or other risks that affect all units), the lower is the diversification benefit of multiple units of the same type. This is illustrated with the example of BC Ferries fast ferries on page 14 of my testimony (Ex. C1-1-1, Attachment 3, p.14) where multiple ferries of the same type experienced the same operational challenges and therefore did not reduce risk.

To be clear, diversification benefits can exist if there are no intrinsic defects. For example, an aircraft model may be well designed, but a particular plane may not operate well due to an issue specific to that unit. In that case, financing a fleet of aircraft (of this model) would benefit from diversification since there are no intrinsic defects. But, in the absence of performance guarantees from the manufacturer, financing the single plane would be subject to concentration risk (i.e. if it was grounded, there would be no cash flow stream to service debt).

Board Staff Interrogatory #045

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 3 / p. 19

Preamble:

Polar Star stated the following:

> I expect that it will take multiple bond issuances and some years to achieve an optimal capital structure for the SPV.

OEB staff notes below that the question is directed to Polar Star

Question(s):

a) Polar Star: What is an "optimal capital structure" for the Darlington New Nuclear Program (DNNP)?

Response

This response was prepared by Polar Star Advisory Services ("Polar Star")

a) In general, an optimal capital structure represents a mix of debt and equity financing that minimizes a company's weighted average cost of capital while maximizing its overall market value. In doing so, it incorporates a balancing of the tax benefits of debt against the risks of financial distress.

   Specifically, for DNNP LP, I expect that the optimal capital structure will be achieved over time given the potentially large size of the expected bond program in the context of the Canadian capital markets. As more units come on-line and as a track record of operations and cash flow generation is developed and proven to the investor base, it is reasonable to expect DNNP LP to have access to a wider range of bond investors and that the size of investment "holds" by any particular investor would increase.

   Once all units are completed and construction risk is removed, interface risk between units is reduced, and bond investor comfort with the assets increases, it is reasonable to expect that non-recourse debt levels can be increased, and equity levels reduced. An optimal debt level is not universal, as it varies heavily by

industry, cash flow stability, and growth stage. The optimal debt level would be achieved when debt can be serviced over an acceptable range of adverse economic and operating scenarios while maintaining credit metrics (e.g., funds from operations to debt, debt to EBITDA) acceptable to credit rating agencies and bond investors.

The optimal level of non-recourse debt will be influenced by many factors including, but not limited to: (i) the analyses and conclusions from credit rating agencies; (ii) actual versus budgeted down time of the units and the stability of cash flow; (iii) forecasted interest/debt service coverage ratios and other credit metrics; and (iv) whether all units are successfully operating with a strong track record. Any estimate of the optimal capital structure would be speculative at this stage given that, among other things, this particular asset has never been previously built and there is presently no assurance how many units will actually be constructed under the DNNP.

Board Staff Interrogatory #046

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 3 / p. 7

Preamble:

Polar Star stated the following:

> For the reasons stated herein, but primarily due to FOAK nuclear technology risk and related operating risk, I believe that there is a low to very low probability of a successful offering of investment grade non-recourse bonds within 12-18 months following the in-service date of the first SMR unit for the DNNP.

OEB staff notes below that the questions are directed to Polar Star.

Question(s):

a) Polar Star: Please elaborate on the meaning of the phrase “successful offering” in this statement.

b) Polar Star: How was the "12-18 month" period after in-service date determined to be the appropriate time to issue debt?

Response

This response was prepared by Polar Star Advisory Services (“Polar Star”)

a) As I stated on page 9 of my testimony:

> “*References herein to a successful bond offering means that the financing is a reasonable dollar size and distribution is to an acceptably broad range of investors such that market participants view the outcome favourably. This description of a successful bond offering is typical of any inaugural offering where the issuer plans ongoing bond issues.” (Ex. C1-1-1, Attachment 3, p. 9)*

Similarly on page 32 of my testimony, I stated the following:

> *"Generally, first time issuers make every effort to achieve a successful first offering to increase investor appetite and lower the pricing of future offerings. As noted earlier, a successful offering means that the financing is a reasonable dollar size and distribution is to an acceptably broad range of investors such that market participants view the outcome favourably."*

Consistent with the above, in the case of an issuer that is planning for an ongoing bond issuance program (as opposed to an issuer that is only coming to the market once), a successful bond offering should have sufficient breadth of demand. For investors to want to buy an inaugural issue as well as subsequent bonds, they typically focus on several characteristics including, for example:

i. broad acceptance of the bond issues by the investor community
ii. reasonable liquidity (i.e., ability to buy or sell bonds with an acceptably tight bid-offer spread) which generally requires a minimum bond size and breadth of offering
iii. fair pricing in the context of other bonds available in the market
iv. access to information (i.e., issuer provides investors with access to management as well as financial and operational information)
v. a stable or improving credit profile and an expectation of stable or tightening credit spreads
vi. no single, crucial point of weakness (such as technology risk, access to critical inputs, significant market price risk, single buyer unless very creditworthy) in an otherwise strong entity.

b) Please refer to Ex. L-C1-Staff-041 parts c) and d).

Board Staff Interrogatory #047

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 3 / p. 33

Preamble:

Polar Star stated the following:

> Having a reasonable operating period after the in-service date is, I believe, critical for a successful first bond offering.

OEB staff notes below that the question is directed to Polar Star

Question(s):

a) Polar Star: What is the typical amount of time in service before a company will issue bonds to finance new capital infrastructure projects?

Response

This response was prepared by Polar Star Advisory Services ("Polar Star")

a) I have interpreted this question as it applies to a new capital infrastructure project issuing bonds post completion. There is no typical amount of time that an infrastructure asset is in service prior to an inaugural non-recourse bond issue. Each case depends on the unique circumstances, including risk profile, and operating experience of the project and factors such as those identified in Ex. L-C1-Staff-41 parts c) and d) and Ex. L-C1-Staff-43 part b).

   In my experience, issuers who access the bond markets after project completion for non-recourse financing generally do so after the project achieves a steady-state risk profile (i.e., after the start-up phase and after cash flows have stabilized) to attract lower cost long-term financing. I believe that the start up phase for a power generation project using proven technology is likely to be materially different from that of a FOAK nuclear plant. In the case of the DNNP, precedents therefore would be of limited value given the presence of the nuclear FOAK technology risk.

Board Staff Interrogatory #048

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 3 / p. 29

Preamble:

Polar Star stated the following:

> It may be undesirable, even if technically feasible, for the SPV to negotiate the final terms of the trust indenture too early, as the perceived risk profile would likely be better a year or more after the inservice date. Deferring the indenture for some such period could therefore lead to a more SPV friendly trust indenture, resulting in increased flexibility and the avoidance of potential future costs associated with modifying the trust indenture, or worse, having to create a more expensive future financing structure (e.g., senior and subordinated debt) due to restrictions in the trust indenture.

OEB staff notes below that the questions are directed to Polar Star.

Question(s):

a) Polar Star: Can trust indentures be renegotiated? (For example, could Darlington New Nuclear Program (DNNP) issue bonds with a relatively stringent trust indenture, but, following 12-18 months of successful in-service use of the plant, renegotiate a new trust indenture on new terms?)

b) Polar Star: Please explain the likelihood of any renegotiating of an initial trust indenture impacting the terms of future trust indentures.

c) Polar Star: Please explain whether the terms would typically be more or less favourable.

Response

This response was prepared by Polar Star Advisory Services ("Polar Star")

a) While it is theoretically possible to renegotiate trust indentures, it is my experience that this is not at all common, save for financial distress situations. Renegotiating a trust indenture is a time-consuming process, requires obtaining approval from

existing bondholders and can be costly (legal fees, investment banker fees and bondholder fees). Critically, existing bondholders have limited, if any, incentive other than fees proposed by the issuer to induce them to voluntarily accept more lenient terms and/or covenants than they originally agreed to. Moreover, bondholders must be comfortable with the proposed amendments and fees and there is therefore no assurance that the renegotiation process would be successful.

While an issuer can repay all bondholders prior to the maturity date and effectively nullify the trust indenture, this is a very expensive approach as it involves paying "make-whole" payments to bondholders. It too, is very uncommon.

If an issuer tried to renegotiate a trust indenture relatively soon after an inaugural bond issue, I expect that investors may question whether the issue was undertaken in good faith, potentially resulting in enduring reputational harm to future issuances.

For clarity, the conclusion in my testimony that there is a low to very low probability of a successful investment grade non-recourse offering within 12-18 months of the Unit 1 in-service date was made, for the reasons stated, irrespective of the stringency of the trust indenture terms. It is my opinion that investors purchasing such bonds will not accept a higher investment grade spread or more stringent terms and conditions to offset the fundamental risk of FOAK technology.

b) Based on my professional judgment, I do not think that the idea of issuing a bond under a trust indenture with the intention of renegotiating it within a few years is an appropriate financing strategy. There is no assurance that investors would willingly surrender protections that were agreed a short time earlier and instead accept more lenient terms. Even if it were possible, there is no assurance that the cost to induce bondholders to accept more lenient terms would be acceptable to DNNP LP. As a result, DNNP LP may be forced to continue new bond issuances under the terms of the original trust indenture.

c) As noted above, I think there is a low to very low probability of a successful non-recourse investment grade bond issue in the first 12-18 months of the DNNP Unit 1 in-service date. As discussed in parts a) and b), I would not expect that a renegotiation of trust indenture terms soon after an inaugural issue would be well received by bond investors and I do not think, on an overall basis, more favourable trust indenture terms would be achieved, even if such a renegotiation was possible.

Board Staff Interrogatory #049

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 37

Preamble:

Concentric stated the following:

> Some stations will require a full redevelopment of the site, with larger project scope and extensive demolition. For some of these assets, these major refurbishment or rehabilitation investments represent first-of-a-kind work on equipment over 100 years of age. One risk associated with projects of these types and on aged assets is the uncertainty of not knowing the exact condition of some of the more inaccessible components of each facility when the work begins. This can lead to increased costs or extended construction schedules (or both), depending on the conditions encountered.

OEB staff notes below that the question is directed to Concentric.

Question(s):

a) Concentric: What are the first-of-a-kind work planned for the hydroelectric refurbishment?

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Concentric understands first-of-a-kind work planned for hydroelectric refurbishment to include those described in Ex. D1-1-2 that R.H. Saunders GS, Unit 9 experienced. As stated in Exhibit D1-1-2, at p. 25, "[t]he [R.H. Saunders GS, Unit 9 capital refurbishment] project experienced longer-than-planned durations for unit refurbishment activities, many of which were first-of-a-kind at the R.H. Saunders GS. Execution activities, including stay ring machining, the removal and replacement of the discharge ring, the removal of the turbine outer head cover, and the alignment of the new pivot ring, took more time to complete than anticipated. Delays were driven in part by as-found conditions, with complexities exacerbated by greater-than-anticipated challenges from AAR impacting concrete-embedded components at the facility. These issues led to additional refurbishment scope not anticipated during project planning." While such work was completed for Unit 9,

Concentric understands that scope and timing for refurbishment or redevelopment work is unique for each station or even generating units within a station, depending on factors including age, condition, refurbishment/overhaul history, manufacturer, and the like. Other work for hydroelectric refurbishment includes the examination and replacement of concrete in the dams to address any concrete degradation, which, for many dams, has not been completed previously. A significant challenge associated with this type of work is that the extent of the work required is unknown. As described in Concentric's report (Ex. C1-1-1, Attachment 1, p. 37), determining the severity of concrete degradation may require invasive procedures.

Board Staff Interrogatory #050

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 50

Preamble:

Concentric stated the following:

> As noted earlier in this report, OPG is rated A(low) (DBRS)/BBB+(S&P)/A3 (Moody's). There is evidence, however, that OPG is perceived from a financial perspective to be of higher risk than similarly rated utilities, as demonstrated through an analysis of credit spreads (i.e., the spread in borrowing costs over Treasury yields) that indicates that bond investors require a higher credit spread premium when investing in OPG bonds.
>
> This phenomenon can be examined by comparing new issue credit spreads for indices of A-rated (i.e., for issuers with composite rating of A+, A, or A- ratings) to those of OPG. As shown in the figures below, OPG's credit spreads have remained consistently above the A-rated regulated utility credit spreads since January 2022. From January 1, 2022 to November 3, 2025, the average difference between OPG's credit spread and the A-rated Canadian utility average spread was approximately 20 basis points, with OPG demonstrating a wider spread over the entire period of analysis.

OEB staff notes below that the questions are directed to Concentric.

Question(s):

a) Concentric: Please provide a table of the credit ratings for each of the six utilities (Hydro One Inc., Enbridge Gas Inc., EPCOR Utilities Inc., CU Inc., Toronto Hydro Corporation, and Alectra) contained in the analysis found in Figures 11 and 12.

b) Concentric: Please explain why none of the companies that appear in the proxy group for the capital structure analysis were included in the sample of utilities used in the comparison of bond spreads.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Please see Chart 1 below:

Chart 1 – Credit Ratings for Six Utilities

	DBRS	S&P	Moody's	Fitch
Hydro One Inc.	A(high)	A	A3	n/a
Enbridge Gas Inc.	A	A-	n/a	n/a
EPCOR Utilities Inc.	A(low)	n/a	n/a	A-
CU Inc.	A(high)	n/a	n/a	A-
Toronto Hydro Corp	A	A+	n/a	n/a
Alectra	A	A-	n/a	A-
OPG	*A(low)*	*BBB+*	*A3*	*n/a*

b) As noted in footnotes 103 and 104 in Concentric's report (Ex. C1-1-1, Attachment 1, p. 51), the new credit spread analysis reflected in Figures 11 and 12 was based on data provided to OPG by Bank of Montreal, Bank of Nova Scotia, Canadian Imperial Bank of Commerce, National Bank Financial, Toronto-Dominion Bank, and Royal Bank of Canada, and thus reflects data as provided to OPG from the cited banking institutions. Based on this available data, the credit spread analysis demonstrates both that OPG is perceived from a financial perspective to be of higher risk than similarly rated utilities and further demonstrates that credit ratings alone do not fully capture investor sentiment regarding utility risk.

Board Staff Interrogatory #051

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p.52

Preamble:

Concentric stated the following:

> OPG also faces higher business risks due to severe weather and cyber-security than in 2016 or 2020, with weather events and cyber threats on the rise.

OEB staff notes below that the questions are directed to Concentric.

Question(s):

a) Concentric: How does severe weather affect hydroelectric power generation in Ontario?

b) Concentric: How does severe weather affect nuclear power generation in Ontario?

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Severe weather risk is discussed on pages 37-39 of Concentric's report (Ex. C1-1-1, Attachment 1, pp. 37-39). There, Concentric provided specific examples of how historic flooding events and heightened wildfires have affected the business operations of OPG in the past several years. For example, severe weather has caused damage to hydroelectric generating stations, requiring additional costs for capital upgrades and maintenance to repair damage. Severe weather has also caused system outages, affecting the amount of revenue collected by OPG. These risks have intensified since 2020 and are anticipated to continue to do so over the five-year period from 2027 to 2031. Severe weather is also increasingly leading to regulatory directives and additional reliability standards for utilities.

b) Severe weather has less effect on nuclear power generation in Ontario than on hydroelectric generation, but the generation facilities must be designed and built to withstand all types of weather events such as floods, wildfires, earthquakes and the

like. To the extent those events become more frequent and/or severe, the costs and regulatory requirements for OPG are likely to increase.

Additionally, both hydroelectric and nuclear stations are subject to impacts that severe weather has on the transmission grid that could impact their ability to generate.

Board Staff Interrogatory #052

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 61

Preamble:

Concentric stated the following:

> Given the unique characteristics of OPG, and, in particular, the fact that its regulated operations consist of 100% generating assets, it is not possible to find proxy companies that are perfectly comparable from a risk perspective. At issue, then, is how to determine an appropriate equity ratio in the context of that range.

OEB staff notes below that the questions are directed to Concentric.

Question(s):

a) Concentric: What determines whether an equity ratio is "appropriate"?

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Concentric uses the Fair Return Standard ("FRS") to assess whether a deemed equity ratio is appropriate. As discussed in Section 3 of the Concentric report, the FRS includes three components:

1. Comparable investment standard,
2. Financial integrity standard, and
3. Capital attraction standard.

All three standards must be met, and none ranks in priority to the others. The FRS applies to both the authorized ROE and the deemed capital structure. The OEB affirmed these principles in EB-2024-0063.[1]

In addition, Concentric considered the "stand-alone principle," which states that a utility should be regulated as if it were a stand-alone entity, raising capital on the merits of its own business and financial characteristics. The OEB has previously

[1] Decision and Order, EB-2024-0063, March 27, 2025, p. 4 and p. 34.

found that “the cost of capital should be determined based on the use of funds and the risk profiles of utilities, rather than the ownership type or capital source.”[2] In addition, the deemed equity ratio and authorized ROE must be considered together to determine whether the FRS has been met.

[2] Decision and Order, EB-2024-0063, March 27, 2025, p. 18.

Board Staff Interrogatory #053

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 63 & 66

Preamble:

Concentric stated the following:

> To develop the proxy group, Concentric conducted a series of screens based on OPG's operating profile to refine all publicly-traded North American investor-owned utility companies to those with similar operating characteristics to OPG. To begin the screening process, Concentric began with all U.S. Electric Utilities, as categorized by Value Line, and publicly-traded Canadian utilities.

In Figure 15, Concentric provided its list of utilities included in its peer groups.

OEB staff notes below that the questions are directed to Concentric.

Question(s):

a) Concentric: Why was it necessary to consider only publicly traded companies?

b) Concentric: Please explain why no government-owned utilities were included in any peer groups?

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Concentric considered only publicly-traded companies in the proxy group because they raise equity from investors in capital markets. Standard cost of equity methodologies require observable market data, which is available only for publicly traded companies. While Concentric's analysis is focused on capital structure in this proceeding, rather than the return on equity ("ROE"), the combination of the equity ratio and the ROE is what determines the return to shareholders, and investors evaluate the capital structure in assessing financial risk. In addition, due to disclosure requirements, publicly-available data is readily available on a consistent basis across publicly-traded entities, which is not the case for privately-held firms.

b) The cost of capital is a market-based concept. Accordingly, Concentric selected publicly traded proxy companies in part to ensure that the data collected for the utilities included in the proxy group is market-based data. Further, many government-owned utilities have credit ratings that are materially higher than OPG's (e.g., British Columbia Hydro and Power Authority ("BC Hydro") is rated A+ by S&P, and Hydro-Québec is rated A+ by S&P, and Newfoundland and Labrador Hydro is rated A by S&P). These ratings reflect explicit provincial or federal support rather than stand-alone utility credit risk: BC Hydro, Hydro-Québec, Manitoba Hydro and Newfoundland and Labrador Hydro have provincially guaranteed debt with ratings that move in lockstep with their respective provinces.[1] Accordingly, Concentric excluded government-owned utilities from its proxy group because those utilities do not provide meaningful market-based capital structure data for OPG.

Refer also to Concentric's response to Ex. L-C1-Staff-24 and Ex. L-C1-Staff-52, which discuss the long-standing stand-alone principle that has been consistently applied by the OEB, including the OEB's finding that "Provincial ownership will not be a factor to be considered by the Board in establishing capital structure."[2]

[1] OPG, on the other hand, is rated four notches below the Province of Ontario (i.e., four notches below the Province's AA- rating). While S&P, for example, states that it incorporates into its ratings "a high likelihood that its provincial owner, the Government of Ontario, will provide extraordinary support to the utility during periods of financial distress," (see, S&P Global, "Ontario Power Generation Inc.," August 14, 2024, p. 7) the Province does not guarantee or explicitly support OPG's debt.

[2] *Ibid.*, p. 142.

Board Staff Interrogatory #298

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 14, 66, 67, 72, 73, 74, 75, 103-109
Ref 2: Excel file "Authorized Equity Ratio Analysis Workpaper – PUBLIC"
Ref 3: Excel file "Proxy Group Screening Workpaper – PUBLIC"
Ref 4: Excel file "Actual Equity Ratio Analysis Workpaper – PUBLIC"

Preamble:

Concentric included the following figures in its report which are summarized in Table 1 below by OEB staff.

Table 1 – Summary of Concentric's Figures of Peer Groups

Figure No.	Figure Name	Figure Description
1	Summary Statistics for Peer Groups	Shows a graph of some of the data included in Figure 16.
15	Concentric Peer Groups	Shows the utilities in the Main Proxy Group, Nuclear Group, and Hydro Group
16	Summary of Peer Group Analysis	Shows the actual and authorized capital structures (mean and median) for the Main Proxy Group, Nuclear Group, and Hydro Group.
17	Fair Return Standard Analyses of Equity Ratios	Shows a graph of some of the data included in Figure 16.
21	Concentric Proxy Group Equity Ratios	Shows the holding companies 5-year average actual capital structures % and average authorized capital structures %
23	Equity Ratios – Concentric Proxy Group vs. "Most Credit Supportive" Jurisdictions	Shows the mean, median, minimum, and maximum authorized capital structures for the Main Proxy Group and the Most Credit Supportive Group
24	FRS Analysis of Equity Ratios – Concentric and "Most Credit Supportive" Proxy Groups	Shows a graph of some of the data included in Figure 23

At footnote 145, Concentric stated the following:

> Figure 23 illustrates only the subset of "most credit supportive" jurisdictions as a result of a screening process of the main Concentric Proxy Group. In the U.S., the resulting states were Michigan, Kentucky, Florida, Alabama, and Wisconsin. In Canada, only British Columbia passed the screen…

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In the first above noted Excel file, tab “Authorized Equity Ratios”, column J describes the level of S&P credit supportiveness. The other above noted Excel files do not address the level of S&P credit supportiveness.

OEB staff notes that the questions are directed to Concentric.

Question(s):

a) Please confirm that “Table 1 – Summary of Concentric’s Figures of Peer Groups” is accurate. Please update the table as applicable and explain any changes made.

b) Please explain why Figure 23 and Figure 24 illustrate only a subset of most credit supportive jurisdictions, as a result of Concentric’s screening process of the Main Proxy Group, as opposed to all credit supportive jurisdictions.

c) Please explain why the utilities in the Most Credit Supportive Jurisdictions Proxy Group are not listed in the following Excel files, as well as the figures in “Table 1 – Summary of Concentric’s Figures of Peer Groups”, and pages 103-109 of the Concentric report:
   i. Excel file “Authorized Equity Ratio Analysis Workpaper – PUBLIC”, tab “Authorized Equity Ratios” and tab “Holding Company Averages”
   ii. Excel file “Proxy Group Screening Workpaper – PUBLIC”, tab “Proxy Group Screen” and tab “Final Proxy Groups”
   iii. Excel file “Actual Equity Ratio Analysis Workpaper – PUBLIC”, tab “Summary Holdcos” and tab “Proxy Group”

d) Please update the references and analysis included in part c) of this question to include the utilities in the separate grouping for the Most Credit Supportive Jurisdictions Proxy Group.

Response

This response was prepared by Concentric Energy Advisors (“Concentric”)

a) Confirmed that the column “Figure Description” in Table 1 provides an accurate high-level summary of the information presented in the referenced figures. As a point of clarification regarding Figure 21, the holding company average actual and authorized equity ratios represent the average of each holding company’s operating companies’ actual and authorized equity ratios, as noted in footnote 138 and 139 to Concentric’s report (Ex. C1-1-1, Attachment 1, p. 72).

b) Screening for operating company jurisdictions only within the main proxy group (i.e., the "Concentric Proxy Group") enabled Concentric to compare the results against the main Concentric Proxy Group, to isolate the effects, if any, a "Most Credit Supportive" ranking had on equity ratio results. The "Most Credit Supportive" screen is not a traditional screen applied by Concentric, but, as described on page 74 of Concentric's report, Concentric conducted that additional screening process in consideration of the OEB's findings in EB-2024-0063. The companies included in the "Most Credit Supportive" subgroup are provided below.

Operating Company	**Parent Ticker**	**Operating Jurisdiction**
Indiana Michigan Power Company	AEP	Michigan
Kentucky Power Company	AEP	Kentucky
Duke Energy Florida, LLC	DUK	Florida
Duke Energy Kentucky, Inc.	DUK	Kentucky
Florida Power & Light Company	NEE	Florida
Alabama Power Company	SO	Alabama
Northern States Power Company	XEL	Wisconsin
Tampa Electric Company	EMA	Florida
FortisBC Inc.	FTS	British Columbia

Based on the additional analysis of this subgroup, Concentric concluded that this screening approach did not materially change the high end, mean, or median results of the Concentric Proxy Group.

c) Concentric responds as follows:

- The utilities that operate in the "Most Credit Supportive" jurisdictions can be found in the Excel file labeled "Authorized Equity Ratio Analysis Workpaper – PUBLIC" on the "Authorized Equity Ratios" tab, Excel column J. The tab "Holding Company Averages" in that file reflects the averages for the main peer group, without consideration of the subgroups.
- The utilities that operate in the "Most Credit Supportive" jurisdictions are not reflected in the Excel filed labeled "Proxy Group Screening Workpaper – PUBLIC" because that file reflects data at the holding company level, whereas the "Most Credit Supportive" designation is done at the province/state level. The main proxy group, nuclear subgroup, and hydroelectric subgroup were screened at the holding company level.

- Concentric did not analyze the actual equity ratios for the "Most Credit Supportive" peer subgroup because the actual equity ratios are reported at the operating company level that, in some cases, operate across multiple jurisdictions. For that reason, the "Most Credit Supportive" peer subgroup is not analyzed in the Excel file titled "Actual Equity Ratio Analysis Workpaper – PUBLIC."
- Regarding Figure 1 to Concentric's report, as described in response to part b) of this response, the "Most Credit Supportive" screen is not a traditional screen applied by Concentric, but, as described on page 74 of Concentric's report, Concentric conducted that additional screening process in consideration of the OEB's findings in EB-2024-0063.
- Regarding Exhibits 2 through 4 to Concentric's report (i.e., pages 103-109 of Concentric's report (Ex. C1-1-1, Attachment 1)), utility operating companies (both those operating in "Most Credit Supportive" jurisdictions and those not operating in those jurisdictions). are subsidiaries of the companies listed in Exhibit 2 (pages 103-105 of Concentric's report). Exhibit 3 (page 106), which analyzes actual equity ratios, reflects only the nuclear and hydroelectric subgroup results for the reasons described above. The operating companies that operate in "Most Credit Supportive" jurisdictions are listed on Exhibit 4 (pages 107 and 108). The last page of Exhibit 4 (page 109) reports data for the main proxy group only.

d) Concentric has provided the files below to additionally include the list of operating company jurisdictions in the "Most Credit Supportive" group:
   - Figure 1 and 17, and the data supporting Figure 16: Attachment 1
   - Figure 15: Attachment 2
   - Excel file "Authorized Equity Ratio Analysis Workpaper – PUBLIC": Attachment 3.

   Note that these attachments include Virginia Electric and Power Company's ("VEPCo's") authorized equity ratio in Virginia, consistent with Concentric's response to Ex. L-C1-Staff-302 parts a) and b). VEPCo is not included in the "Most Credit Supportive" group.

Figure 15: Concentric Peer Groups

All Value Line U.S. Electric Utilities and Publicly-Traded Canadian Utilities

Application of screening criteria listed above

Main Peer Group

Company	Ticker
ALLETE, Inc.	ALE
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Dominion Resources, Inc.	D
Duke Energy Corporation	DUK
Edison International	EIX
Entergy Corporation	ETR
Evergy, Inc.	EVRG
IDACORP, Inc.	IDA
NextEra Energy, Inc.	NEE
Pinnacle West Capital Corporation	PNW
TXNM Energy, Inc.	TXNM
Portland General Electric Company	POR
Southern Company	SO
Xcel Energy Inc.	XEL
Algonquin Power & Utilities Corporation	AQN
Emera Inc.	EMA
Fortis Inc.	FTS

Most Credit Supportive Group

Company	Ticker	Operating Jurisdiction
Indiana Michigan Power Company	AEP	Michigan
Kentucky Power Company	AEP	Kentucky
Duke Energy Florida, LLC	DUK	Florida
Duke Energy Kentucky, Inc.	DUK	Kentucky
Florida Power & Light Company	NEE	Florida
Alabama Power Company	SO	Alabama
Northern States Power Company	XEL	Wisconsin
Tampa Electric Company	EMA	Florida
FortisBC Inc.	FTS	British Columbia

Nuclear Group

Company	Ticker
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Dominion Resources, Inc.	D
Duke Energy Corporation	DUK
Edison International	EIX
Entergy Corporation	ETR
Evergy, Inc.	EVRG
NextEra Energy, Inc.	NEE
Pinnacle West Capital Corporation	PNW
TXNM Energy, Inc.	TXNM
Southern Company	SO
Xcel Energy Inc.	XEL

Hydroelectric Group

Company	Ticker
ALLETE, Inc.	ALE
Edison International	EIX
IDACORP, Inc.	IDA
Portland General Electric Company	POR
Southern Company	SO

Board Staff Interrogatory #299

Interrogatory

Reference:
Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 14, 66, 67, 72, 73, 74, 75, 103-109
Ref 2: Excel file "Authorized Equity Ratio Analysis Workpaper – PUBLIC"
Ref 3: Excel file "Proxy Group Screening Workpaper – PUBLIC"
Ref 4: Excel file "Actual Equity Ratio Analysis Workpaper – PUBLIC"

Preamble:

In the interrogatories below OEB staff has asked questions about the following utilities:

- NextEra and Florida Power & Light Co
- Dominion Resources, Virginia Electric and Power Company, Dominion Energy South Carolina, Dominion Energy's subsidiary in Virginia
- Ameren Corporation, Union Electric Company, Ameren Illinois Company
- Algonquin Power & Utilities Corporation, Liberty Utilities (CalPeco Electric) LLC, Liberty Utilities (Granite State Electric) Corp., The Empire District Electric Company
- Emera Inc. and Tampa Electric Company
- Fortis Inc., Central Hudson Gas & Electric Corp., Tucson Electric Power Company, and UNS Electric, Inc.

OEB staff notes that the questions are directed to Concentric.

Question(s):

a) Based on the questions below asked by OEB staff, please explain whether the authorized and/or actual capital structure values related to each of the above-noted utilities should be omitted from:
   i. The figures in OEB staff's "Table 1 – Summary of Concentric's Figures of Peer Groups"
   ii. The related Excel files described in question C1-01-Staff-298 part c), and
   iii. Pages 103-109 of Concentric's report

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Concentric agrees that Virginia Electric and Power Company's ("VEPCO's") operations in Virginia should be added to the analysis. Please refer to Ex. L-C1-Staff-298 Attachment 1 for a revised version of Figures 1 and 17, and the data supporting Figure 17, including VEPCo in Virginia. As discussed in the responses to Ex. L-C1-Staff-302 through Ex. L-C1-Staff-306, the figures should not be modified to exclude the remainder of the companies provided in the preamble to this interrogatory.

Board Staff Interrogatory #300

Interrogatory

Reference:
Ref 1: Excel file "Authorized Equity Ratio Analysis Workpaper – PUBLIC"
Ref 2: Exhibit C / Tab 1 / Schedule 1 / Attachment 1 / pp. 62-67

Preamble:

The Concentric Report states:

> In addition to the Concentric Proxy Group, a secondary screen for companies with a minimum threshold of nuclear capacity (i.e., 5% or more MW capacity) was conducted to form the Nuclear Group. This group comprised of a subset of 12 U.S. utilities from the Concentric Proxy Group. Finally, to reflect the risk inherent in OPG's hydroelectric generation operations, Concentric created another subset of the Concentric Proxy Group that screened for a minimum threshold of hydroelectric capacity (i.e., 5% or more MW capacity). (p. 65)

OEB staff notes that the questions are directed to Concentric.

Question(s):

a) How was five percent chosen as a threshold nuclear and hydroelectric generation in selecting the peer groups?

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) The five percent threshold was used as a practical screening criterion to identify utilities for which nuclear or hydroelectric generation represents a meaningful portion of the generation portfolio and associated risk profile. The intent was to distinguish utilities with material exposure to these technologies from those where such exposure is incidental. The nuclear and hydroelectric groups were developed as secondary reference points within the broader Concentric Proxy Group, not as standalone or exhaustive peer groups.

Board Staff Interrogatory #301

Interrogatory

Reference:
Ref 1: Excel file "Authorized Equity Ratio Analysis Workpaper – PUBLIC"
Ref 2: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 62-72

Preamble:

Referring to Excel file "Authorized Equity Ratio Analysis Workpaper – PUBLIC", Cell Y3 on sheet "Past Rate Cases" reads: "The following states were excluded due to inclusion of zero-cost of capital items in equity ratio authorization." Florida is included on this list of excluded jurisdictions.

However, cell Y438 contains a manually entered number for Florida Power & Light, which conducts business as NextEra. A comment on this cell reads: "Manually added. Internal Concentric Data."

NextEra (NEE) is included in the "Main Peer Group" and "Nuclear Group" found in Figure 15, as well as the list of proxy group equity ratios found in Figure 21.

OEB staff notes that the questions are directed to Concentric.

Question(s):

a) Should NextEra be excluded from the analysis, per the note found in Cell Y3?

b) If NextEra should be included in the analysis, why does the note in Cell Y3 not apply in this instance?

c) If NextEra should be excluded for the reason stated in Cell Y3, should NextEra's capital structure be omitted from the values found in Figure 16 (p. 67), and from the "Max" row in Report Figure 23 (p.75), and the "Group Max" in Report Figure 24 (p. 75)?

d) Please provide an update to Figure 16 with NextEra excluded from the sample.

e) Please provide an update to Figure 17 with NextEra excluded from the sample.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) No. NextEra Energy, Inc. (including Florida Power & Light) should not be excluded from the analysis.

b) The note in Cell Y3 refers to jurisdictions where recent authorized equity ratios per the Regulatory Research Associates ("RRA") database (i.e., the main source of Concentric's data) are not comparable because they incorporate zero cost or non investor supplied capital components directly into the authorized equity ratio, which can distort comparability across utilities.

In the case of NextEra Energy, Concentric relied on direct knowledge of utility specific regulatory and capital structure information gained through Concentric's participation in that rate case to ensure that the equity ratio used in the analysis reflects a conventional common equity component excluding zero-cost capital components that is comparable across the broader proxy group. Additionally, as of April 1, 2026, RRA now reflects Florida Power & Light's most recent rate case with a decision issued November 2025 (D-20250011-EI) and reports an authorized equity ratio excluding zero-cost of capital items of 59.60%.

c) Not applicable. See the response to part b).

d) While excluding NextEra from the proxy group would not improve the relevance or comparability of the proxy group analysis or alter the conclusions drawn from the results, updated versions of Figures 16 and 17 excluding NextEra are provided in Attachment 1 in response to the request. This attachment includes Virginia Electric Operating Company's authorized equity ratio in Virginia, consistent with Concentric's response to Ex. L-C1-Staff-302 parts a) and b). In addition, Ex. L-C1-CCC-031 Attachment 2, which is a modified version of the "Holding Company Averages" and "Authorized Equity Ratios" tabs from Concentric's workpaper entitled "Authorized Equity Ratio Analysis Workpaper – PUBLIC", adjusts authorized equity ratios for utilities operating in jurisdictions that include zero cost sources of financing by removing those zero cost items, based on a review of regulatory orders, settlements, and testimony.

e) See the response to part d).

Board Staff Interrogatory #302

Interrogatory

Reference:
Ref 1: Excel file "Authorized Equity Ratio Analysis Workpaper – PUBLIC"
Ref 2: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 62-72, 106
Ref 3: Attachment 1, RiderGEN_capitalstructure_testimony_2024
Ref 4: Attachment 2, RiderGEN_Decision_2025

Preamble:

Referring to Excel file "Authorized Equity Ratio Analysis Workpaper – PUBLIC", sheet "Authorized Equity Ratios", rows 20 and 21 contain data for two subsidiaries of Dominion Energy: Virginia Electric and Power Company's operations in North Carolina and Dominion Energy South Carolina's operations in South Carolina.

Dominion Resources (D) is included in the "Main Peer Group" and "Nuclear Group" found in Figure 15, as well as the list of proxy group equity ratios found in Figure 21.

Also, Dominion Energy in Virginia has an authorized capital structure specifically applied to the company's generation assets (see attachments "RiderGEN_capitalstructure_testimony_2024" and "RiderGEN_Decision_2025"). This capital structure is set by the Virginia Corporation Commission through a proceeding to determine the parameters for a rate rider called "Rider GEN" for Dominion Energy's Virginia operations. Dominion Energy's subsidiary in Virginia was not included in the analysis, according to sheet "Authorized Equity Ratios" in Excel file "Authorized Equity Ratio Analysis Workpaper – PUBLIC."

OEB staff notes that the questions are directed to Concentric.

Question(s):

a) Does the data in row 20, associated with Virginia Electric and Power Company, labeled "North Carolina" in cell C20, reflect operations of Virginia Electric and Power Company only in North Carolina (and not in Virginia)?

b) If Dominion Energy's operations in Virginia are not included in this analysis, why?

c) Does Virginia Electric and Power Company have any nuclear assets in North Carolina?

d) If not, should Dominion Energy's approved capital structure in North Carolina be included in the "nuclear" proxy group if the company's nuclear operations are not in North Carolina?

e) Please provide an update to Figure 16 with Dominion Energy's North Carolina subsidiary excluded from the sample.

f) Please provide an update to Figure 17 with Dominion Energy's North Carolina subsidiary excluded from the sample.

g) Why was the capital structure for generation assets in Dominion's Virginia subsidiary, as identified by "Rider GEN," excluded from the analysis?

h) Please provide an update to Figure 16 with the Rider GEN capital structure included in the sample.

i) Please provide an update to Figure 17 with the Rider GEN capital structure included in the sample.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Yes.

b) For clarification, Virgina Electric and Power Company's ("VEPCo's") Rider GEN is not applied to all VEPCO's generation. The Company's nuclear facilities, the Surry Nuclear Power Station and the North Anna Nuclear Power Station, are recovered by VEPCo through base rates.

In responding to this interrogatory, Concentric identified that VEPCo's Virginia jurisdiction was incorrectly excluded from Concentric's analysis and should be included because it is a subsidiary of Dominion Resources Inc., which is in the main proxy group. The company is currently authorized a 52.04% equity ratio by the Virginia State Corporation Commission as a result of Docket C-PUR-2025-00058 with Order issued November 25, 2025. See Ex. C1-Staff-298 Attachment 1 for a revision of Figures 16 and 17 including VEPCo's Virginia jurisdiction. Additionally, Concentric has added this data point in other relevant interrogatory responses where appropriate.

c) VEPCo does not have any nuclear assets in North Carolina.

d) Yes. Dominion Energy's approved capital structure in North Carolina is included in the nuclear proxy group based on its inclusion within Virginia Electric and Power Company's multi-jurisdiction operations.

e) While excluding Dominion Energy's North Carolina subsidiary from the proxy group would not improve the relevance or comparability of the proxy group analysis or alter the conclusions drawn from the results, updated versions of Figures 16 and 17 excluding Dominion Energy's North Carolina subsidiary are provided in Attachment 1 in response to the request. Note that as jurisdictional-level actual balance sheet data is not available, only the authorized equity ratio analysis changed. In addition, Concentric has provided tabs excluding VEPCO's North Carolina operations from all groups and from the nuclear group only. Also note that this attachment includes Virginia Electric Operating Company's authorized equity ratio in Virginia, consistent with Concentric's response to parts a) and b).

f) See the response to part e).

g) See the response to part b). For practical purposes, the equity thickness provided in "RiderGEN_capitalstructure_testimony_2024" (i.e., 51.99%), is virtually identical to VEPCO's currently authorized 52.04%.

h) See Attachment 2 for the requested data. The 2025 Decision in the latest Rider GEN proceeding, Virginia State Corporation Commission Docket PUR-2024-00097 states that the Company's proposed capital structure was approved. The Company's direct testimony in that case indicates a proposed equity ratio of 51.99%. As such, Concentric included the 51.99% data point in the requested analysis. This attachment includes VEPCO's authorized equity ratio in Virginia, consistent with Concentric's response to parts a) and b).

i) See the response to part h).

Board Staff Interrogatory #303

Interrogatory

Reference:
Ref 1: Excel file "Authorized Equity Ratio Analysis Workpaper – PUBLIC"
Ref 2: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 62-67
Ref 3: Attachment 3, AmerenCorporateFactSheet
Ref 4: Attachment 4, AmerenIllinois_Form1_2024
Ref 5: Attachment 5, UnionElectric_Form1_2024

Preamble:

According to page 1 of Ameren Illinois's "Corporate Facts" ("AmerenCorporateFactSheet," attached): "Ameren Illinois is a delivery-only utility." Plant in Service data from Ameren Illinois's FERC Form 1 for 2024 (p. 204-207 and p. 406-411 of "AmerenIllinois_Form1_2024," attached) indicates that Ameren Illinois does not own substantial generation plant. In particular, Ameren Illinois reports only one generating plant, a solar facility called East St. Louis Solar Energy Center, which has a Net Peak Demand of 1.5 MW.

Union Electric Company does own generation plant (see "UnionElectric_Form1_2024," attached).

Referring to Excel file "Authorized Equity Ratio Analysis Workpaper – PUBLIC", sheet "Authorized Equity Ratios", row 5 contains data for Ameren Illinois Company. The analysis uses the authorized capital structure for Ameren Illinois (50% equity) to represent the entirety of Ameren Corporation, but does not use the authorized capital structure for Union Electric Company.

Ameren Corporation is included in the "Main Peer Group" and the "Nuclear Group" in Figure 15, as well as the list of proxy group equity ratios found in Figure 21.

OEB staff notes that the questions are directed to Concentric.

Question(s):

a) Why should the analysis include Ameren Corporation if an authorized capital structure is not available for the subsidiary (Union Electric Company) that owns generation plant?

b) If Ameren Corporation should be included in the proxy group, why should Ameren Illinois, which does not own substantial generation plant, serve as the sole data point for Ameren Corporation's authorized capital structure?

c) Please provide an update to Figure 16 with Ameren Corporation excluded from the sample.

d) Please provide an update to Figure 17 with Ameren Corporation excluded from the sample.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Peer group companies were screened at the holding company level, and Concentric applied a consistent methodology under which all operating subsidiaries of each peer holding company were considered. Peer holding companies that passed the screening criteria, including Ameren Corporation, are therefore reasonable comparators to OPG from a risk perspective based on consolidated business and financial characteristics assessed by capital markets. Peer holding companies that passed the screening criteria, including Ameren Corporation, are therefore reasonable comparators to OPG from a risk perspective based on consolidated business and financial characteristics assessed by capital markets.

b) Concentric's analyses are based on the application of consistent screening and data methodologies across all peer companies at the consolidated parent company level. Concentric acknowledges that Ameren's Illinois delivery focused operations, considered on a standalone basis, are not directly comparable to OPG's generation activities. However, the analysis is conducted at the consolidated parent company level, consistent with how equity investors evaluate risk across diversified utility enterprises that operate through multiple regulated subsidiaries with differing asset and business mixes.

c) While excluding Ameren Corporation from the proxy group would not improve the relevance or comparability of the proxy group analysis or alter the conclusions drawn from the results, updated versions of Figures 16 and 17 excluding Ameren Corporation are provided in Attachment 1 in response to the request. This attachment includes Virginia Electric Operating Company's authorized equity ratio in Virginia, consistent with Concentric's response to Ex. L-C1-Staff-302 parts a) and b).

d) See the response to part c).

Board Staff Interrogatory #304

Interrogatory

Reference:
Ref 1: Excel file "Actual Equity Ratio Analysis Workpaper – PUBLIC"
Ref 2: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 62-67

Preamble:

Concentric included Algonquin Power & Utilities Corporation in the study sample "[i]n order to broaden the proxy group to include at least a minimal number of Canadian utilities" (p. 65). However, the three subsidiaries of Algonquin in the sample are Liberty Utilities (CalPeco Electric) LLC, Liberty Utilities (Granite State Electric) Corp., and The Empire District Electric Company.

Algonquin Power & Utilities Corporation (AQN) is included in the "Main Peer Group" found in Figure 15, as well as the list of proxy group equity ratios found in Figure 21.

OEB staff notes that the questions are directed to Concentric.

Question(s):

a) Do any of the three Algonquin subsidiaries used in the study sample conduct any operations in Canada?

b) If not, should this company be excluded from the analysis, since it fails two of Concentric's screens and no data is used based on subsidiaries in Canada?

c) Please provide an update to Figure 16 with Algonquin excluded from the sample.

d) Please provide an update to Figure 17 with Algonquin excluded from the sample.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) No, the three subsidiaries of Algonquin Power & Utilities Corporation ("Algonquin") in the sample do not have any operations in Canada.

b) No, Algonquin should not be excluded from the equity ratio analysis. Algonquin is domiciled in Canada, with headquarters in Oakville, Ontario, and its common equity trades on both the Toronto Stock Exchange and the New York Stock Exchange. As explained in Concentric's report, there are a relatively small number of publicly traded Canadian electric utilities, and Concentric intentionally broadened the proxy group to include at least a minimal number of Canadian utilities.

Further, as discussed in Concentric's report, North American utilities compete for capital in integrated capital markets across Canada and the United States. From that perspective, it is appropriate to include companies in the proxy group that derive a substantial portion of their operating income from regulated electric utility operations, as Algonquin does, regardless of whether the company's operating subsidiaries are located primarily in Canada or the United States.

c) While excluding Algonquin from the proxy group would not improve the relevance or comparability of the proxy group analysis or alter the conclusions drawn from the results, updated versions of Figures 16 and 17 excluding Algonquin are provided in Attachment 1 in response to Staff's request. This attachment includes Virginia Electric Operating Company's authorized equity ratio in Virginia, consistent with Concentric's response to Ex. L-C1-Staff-302 parts a) and b).

d) See the response to part c).

Board Staff Interrogatory #305

Interrogatory

Reference:

Ref 1: Excel file "Actual Equity Ratio Analysis Workpaper – PUBLIC"
Ref 2: Excel file "Authorized Equity Ratio Analysis Workpaper – PUBLIC"
Ref 3: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 62-67

Preamble:

Concentric included Emera Inc. in the study sample "In order to broaden the proxy group to include at least a minimal number of Canadian utilities." (p. 65) However, the Emera subsidiary Tampa Electric Company operates in Florida.

Referring to Excel file "Authorized Equity Ratio Analysis Workpaper – PUBLIC", Cell Y3 on sheet "Past Rate Cases" reads: "The following states were excluded due to inclusion of zero-cost of capital items in equity ratio authorization." Florida was included in this list of states.

Emera (EMA) is included in the "Main Peer Group" found in Figure 15, as well as the list of proxy group equity ratios found in Figure 21.

OEB staff notes that the questions are directed to Concentric.

Question(s):

a) Should Tampa Electric Company be included in the sample, if it is not a Canadian utility and fails the other screening tests?

b) Should Tampa Electric Company be included in the sample, in light of the note on Cell Y3 in Excel "Authorized Equity Ratio Analysis Workpaper – PUBLIC", sheet "Past Rate Cases"?

c) Please provide an update to Figure 16 with Tampa Electric Company excluded from the sample.

d) Please provide an update to Figure 17 with Tampa Electric Company excluded from the sample.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Yes. Tampa Electric Company ("TECO") should be included in the sample because it is an operating subsidiary of Emera Inc. ("Emera"), a Canadian domiciled, publicly traded parent company whose consolidated business and financial risks are assessed by capital markets. Emera is a vertically integrated electric utility holding company with regulated subsidiaries in both Canada and the United States. TECO itself is a vertically integrated utility, which makes it more comparable to OPG's generation focused risk profile than transmission and distribution only utilities.

b) Yes. TECO should be included in the sample. Although Florida is one of the states identified as including zero cost of capital items in authorized capital structures, the authorized equity ratio for TECO is reported as "n/a" in S&P Capital IQ and therefore does not affect the authorized equity ratio analysis. TECO's inclusion is relevant for the actual equity ratio analysis, which reflects observed capital structures at the holding company level rather than jurisdiction specific authorized outcomes.

   Further, as described in Concentric's response to Ex. L-C1-CCC-31, Concentric has conducted an additional review of cases originally marked "n/a" due to the presence of zero-cost-of-capital items. Attachment 2 to Ex. L-C1-CCC-31 adjusts authorized equity ratios, where applicable, to exclude zero-cost-of-capital components based on a review of regulatory orders, settlements, and testimony. Accordingly, TECO's inclusion in the proxy group remains appropriate and does not distort the authorized or actual equity ratio analyses.

c) While excluding TECO from the proxy group would not improve the relevance or comparability of the proxy group analysis or alter the conclusions drawn from the results, updated versions of Figures 16 and 17 excluding TECO are provided in Attachment 1 in response to the request. There was no change to the authorized equity ratio analysis. This attachment includes Virginia Electric Operating Company's authorized equity ratio in Virginia, consistent with Concentric's response to Ex. L-C1-Staff-302 parts a) and b).

d) See response to part c).

Board Staff Interrogatory #306

Interrogatory

Reference:
Ref 1: Excel file "Actual Equity Ratio Analysis Workpaper – PUBLIC"
Ref 2: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 62-67

Preamble:

Concentric included Fortis in the study sample "[i]n order to broaden the proxy group to include at least a minimal number of Canadian utilities" (p. 65). However, the Fortis subsidiaries UNS Electric, Inc., Central Hudson Gas & Electric, and Tucson Electric Power Company do not appear to operate in Canada.

Fortis Inc. (FTS) is included in the "Main Peer Group" found in Figure 15, as well as the list of proxy group equity ratios found in Figure 21.

OEB staff notes that the questions are directed to Concentric.

Question(s):

a) Should UNS Electric, Inc., Central Hudson Gas & Electric and Tucson Electric Power Company (subsidiaries of Fortis, Inc.) be included in the analysis?

b) Please provide an update to Figure 16 with UNS Electric, Inc., Central Hudson Gas & Electric, and Tucson Electric Power Company excluded from the sample.

c) Please provide an update to Figure 17w with UNS Electric, Inc., Central Hudson Gas & Electric, and Tucson Electric Power Company excluded from the sample.

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Yes. UNS Electric, Inc., Central Hudson Gas & Electric, and Tucson Electric Power Company should be included in the analysis because they are operating subsidiaries of Fortis Inc. ("Fortis"), a Canadian domiciled, publicly traded utility holding company whose consolidated business and financial risks are evaluated by equity investors at the parent company level.

Consistent with Concentric's methodology, peer companies are screened and analyzed at the holding company level, reflecting how capital markets assess risk and return. The fact that Fortis's regulated operating subsidiaries included in the analysis are located in the United States does not diminish the relevance of Fortis as a Canadian parent level comparator, particularly given Fortis's diversified portfolio of regulated electric and gas utilities and its participation in North American capital markets.

b) While excluding Fortis from the proxy group would not improve the relevance or comparability of the proxy group analysis or alter the conclusions drawn from the results, updated versions of Figures 16 and 17 excluding Fortis are provided in Attachment 1 in response to Staff's request. This attachment includes Virginia Electric Operating Company's authorized equity ratio in Virginia, consistent with Concentric's response to Ex. L-C1-Staff-302 parts a) and b).

c) See the response to part b).

Board Staff Interrogatory #307

Interrogatory

Reference:
Ref 1: Excel file "CEA Exhibits - Proxy Group Screening Workpaper – PUBLIC"
Ref 2: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 29-33 and 62-67
Ref 3: Excel file "CEA Fig 9 Peer CapEx Workpaper"

Preamble:

On page 29, Concentric cites OPG's projected increase in capital spending as a source of increased risk: "Other than the shifting generation mix for OPG, the most important change in business risk for OPG as compared to 2020 and 2016 is the magnitude of the Company's planned capital expenditure ("CapEx") program over the upcoming rate period from." (sic)

OEB staff notes that the questions are directed to Concentric.

Question(s):

a) Did Concentric consider screening utilities for the proxy groups based on projected CapEx growth? Why or why not?

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) In Concentric's opinion, proxy groups should be screened based on fundamental characteristics that reflect long run business risk. Projected financial metrics, including CapEx forecasts, are inherently uncertain and utility specific, and therefore are not well suited for proxy screening. Accordingly, Concentric did not screen companies based on projected CapEx growth and does not consider such a screen to provide meaningful insight for proxy group selection.

Board Staff Interrogatory #308

Interrogatory

Reference:
Ref 1: Excel file "CEA Exhibits - Proxy Group Screening Workpaper – PUBLIC"
Ref 2: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 62-67

Preamble:

The sheet "Proxy Group Screen" contains several criteria that Concentric used to screen companies for a proxy group with characteristics similar to OPG. In order to be included in the proxy group, companies must obtain 60% of revenue and 60% of net income from regulated activities. In addition, companies must obtain 80 percent of revenue and net income from electricity sales.

OEB staff notes that the questions are directed to Concentric.

Question(s):

a) What percentage of OPG's revenues and net income are from regulated activities?

b) How was the use of 80 percent as the threshold for electricity-related revenue and net income selected?

c) How was the use of 60% as the threshold for regulated related revenue and net income selected?

d) Why is there no minimum threshold for generation plant?

e) Why is there no minimum threshold for nuclear generation?

f) Why is there no minimum threshold for hydroelectric generation?

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Concentric's report is focused only on OPG's regulated business. At the corporate level, in 2025, OPG derived approximately 74% of its revenue and 91% of its income before interest and income taxes ("EBIT") from its Regulated Nuclear

Generation and Regulated Hydroelectric Generation business segments. In 2024, these proportions were 75% and 68%, respectively.

b) The 80% threshold for electricity-related revenue and net income was selected so that the companies in the proxy group, like OPG, derive the predominant share of their revenues and net income from electric utility operations over the past three years. As explained on page 64 of Concentric's report, similar to the regulated revenue and net income screen, the 80% regulated electric revenue and net income screen is not a "bright line," but rather is intended to balance the comparability of the proxy group with the need to maintain a sufficiently robust sample.

c) The 60% threshold for regulated revenue and net income was chosen so that the companies in the proxy group, like OPG's regulated nuclear and hydro facilities, derive the majority of their revenues and net income from regulated operations. As explained on page 64 of Concentric's report, while 60% is not a "bright line" percentage for separating regulated from non-regulated companies, applying this threshold results in a proxy group whose earnings and risk profiles are primarily shaped by regulation rather than by merchant or market-based activities.

d) The generation screen was intended to exclude electric utilities that do not own regulated generation assets. As discussed on page 63 of Concentric's report, investors generally perceive utilities with generation assets to face higher business risk than utilities with only transmission or distribution operations. Rather than applying a minimum generation threshold based on installed capacity, Concentric applied a screen that distinguishes companies with regulated generation risk from those without such exposure, as the latter are not comparable to OPG.

e) As explained on page 65 of Concentric's report, a secondary screen was applied to identify companies that derive at least five percent of their generation from nuclear facilities. The authorized and actual equity ratios for these companies are presented separately from the Main Peer Group to provide additional context regarding nuclear-related risk.

f) As also explained on page 65 of Concentric's report, a secondary screen was applied to identify companies that derive at least five percent of their generation from hydroelectric facilities. The equity ratios for these companies are likewise reported separately from the Main Peer Group to reflect hydroelectric-related risk without using hydroelectric exposure as a proxy group inclusion threshold.

VECC Interrogatory #006

Interrogatory

Reference:
Exhibit C1, Tab 1, Schedule 1, page 2 /O. Reg 53/05
Exhibit H1, Tab 1, Schedule 1 pages 54-

Preamble:

"In his testimony, Mr. Inskip explains that primarily due to the first-of-a-kind risks associated with the DNNP, "there is a low to very low probability of a successful offering of investment grade non-recourse bonds within 12-18 months following the in-service date of the first SMR unit for the DNNP" (C1)

"13. (1) The DNNP generator shall establish a variance account in connection with section 78.1 of the Act that, until the effective date of the first DNNP post-construction payment order, records differences between,

(a) the revenue requirement impacts arising from the DNNP generator's capital structure and cost of debt reflecting the actual amount and cost of borrowing issued by it; and

(b) the amount of the revenue requirement impacts arising from the capital structure and the cost of debt that were included in payments made under section 78.1 of the Act to the DNNP generator. O. Reg. 315/25, s. 12."

"The Application proposes that the above variance recorded in the account be calculated as between the revenue requirement impact of actual eligible non-capital and capital costs and firm financial commitments and such forecast amounts reflected in DNNP LP's corresponding annual revenue requirement approved by the OEB" (H1)

Question(s):

a) Is the DNNP Project Variance Account described at H1 intended to only record the results of 13(1) of Reg 53/05?

b) We are unclear as to how non-capital amounts are authorized to be recorded in the account. Does section (b) of 13.(1) provide that authorization?

c) It is unclear to us what the relevance of 12-18 months is with respect to the operation of the DNNP generator capital structure variance account. Does the

timing of any future debt injection impact the calculations of the balances in this account? If so how?

Response

a) The Applicants interpret "DNNP Project Variance Account" to refer to the Darlington New Nuclear Project Variance Account. This account does not relate to the DNNP Generator Capital Structure Variance Account ("DGCSVA") that is established by O. Reg. 53/05, section 13(1) for DNNP LP and is described at Ex. H1-1-1, Section 6.2, but, as described at Ex. H1-1-1, Section 5.31, is established by O. Reg. 53/05, section 5.4.1(1) for OPG.

b) Non-capital amounts are not authorized to be recorded in either the Darlington New Nuclear Project Variance Account or the DGCSVA. For clarity, eligible non-capital amounts are authorized to be recorded in the Darlington New Nuclear Project Variance Account re Development that is established by O. Reg. 53/05, section 11(1) for DNNP LP and is described at Ex. H1-1-1, Section 6.1.

c) The relevance of the statement in Ex. C1-1-1, p. 2, that "there is a low to very low probability of a successful offering of investment grade non-recourse bonds within 12-18 months following the in-service date of the first SMR unit for the DNNP" is that it supports the Application's proposed 100% equity funded capital structure for DNNP LP for the 2027-2031 period. The forecast in-service date for DNNP Unit 1 is in October 2030 and the IR term ends on December 31, 2031, a period of approximately 15 months. This 15-month period falls within the 12-18 month time frame during which Mr. Inskip has opined there is a low to very low probability of a successful non-recourse investment grade bond issue.

The DGCSVA will record the revenue requirement impact of any differences between the capital structure and cost of debt for DNNP LP reflected in the nuclear payment amounts and DNNP LP's actual capital structure and cost of debt. Therefore, if DNNP LP's capital structure is set at 100% equity in this proceeding and a subsequent debt injection in DNNP LP occurs prior to December 31, 2031, the DGCSVA would record the revenue requirement impact of the resulting difference in these cost of capital variables. The DGCSVA would also record the revenue requirement impact in the converse case where this proceeding sets the nuclear payment amounts using a capital structure for DNNP LP that is less than 100% equity and no equivalent actual debt injection subsequently occurs. Refer to Ex. L-C1-Staff-039 for further explanation of the operation of this account.

VECC Interrogatory #007

Interrogatory

Reference:
Exhibit C1-1-1, Attachment 3
Exhibit D4-4-8 Attachment 1, page 2 of 17

Preamble:

"The SMRs are expected to be constructed and operated through a special purpose vehicle ("SPV") in partnership between OPG, as the majority investor, and Canada Growth Fund ("CGF") and Building Ontario Fund ("BOF"), as minority investors." (C1)

"The four-unit DNNP will be financed using a combination of the corporate debt platform, operating cash flow and other potential sources, with project costs recovered as part of regulated assets." (D4)

Question(s):

a) What is the equity investment of each of the three partners?

b) If the cost of the DNNP investment is funded through debt and OPG operating cash flow what is the rationale for the DNNP to attract 100% equity financing in regulated rates?

c) In case of DNNP default (i.e. if it fails to be completed or operate subsequent to investments being made) would any invested costs recorded in the DNNP variance account remain recoverable?

d) What rate of equity does OPG propose the DNNP account attract. If it is the Board's issued rate please provide a rationale for using this rate.

Response

a) As noted in Ex. A1-4-4, p. 2, subject to the satisfaction of certain conditions, each of Canada Growth Fund ("CGF") and Building Ontario Fund ("BOF") will acquire minority interests in DNNP LP representing up to 15% and 7.5% ownership, respectively, based on investments of up to approximately $2 billion and $1 billion, respectively.

b) The DNNP is no longer being constructed or funded through OPG. The DNNP is now being constructed and will be operated by DNNP LP, under a lease arrangement with OPG. DNNP LP is therefore funding the DNNP. DNNP LP anticipates that the DNNP capital expenditures over the 2026-2031 period will be funded by equity contributions from the partners; no debt financing is forecasted during the 2026-2031 period (Ex. A1-4-4, Attachment 1, p. 7). This expectation is supported by the testimony of Mr. Inskip (Ex. C1-1-1, Attachment 3).

c) Yes, in respect of the Darlington New Nuclear Project Variance Account re Development. Refer to O. Reg. 53/05, sections 14(2)3 and 14(2)4.

d) Yes, the Application proposes that the OEB-issued ROE apply in setting the revenue requirements for DNNP LP. As noted at Ex. C1-1-1, p. 3, "[t]he Application incorporates an ROE of 9.11% for OPG and DNNP LP, as this is the latest rate published by the OEB (October 31, 2025) pursuant to the ROE formula as set out in the OEB's Decision and Order, March 27, 2025, EB-2024-0063." The Applicants have used the latest rate published by the OEB for DNNP LP (and OPG) in line with the EB-2024-0063, Decision and Order, March 27, 2025, which states:

> The OEB also agrees with the submission of OEB staff that the ROE should apply to all utilities and that the determination of the required equity thickness for regulated utilities meeting Ontario's energy needs should address differing risks and circumstances associated with capital acquisition, as noted in Section 3.3 of this Decision. (p. 39)
>
> The OEB does not agree that the ROE is the vehicle to address differences in OEB regulated utilities. It will continue the practice of addressing material differences through the capital structure, as discussed in Section 3.3 of this Decision. (p. 35)

VECC Interrogatory #008

Interrogatory

Reference:
Exhibit C1-1-1, Attachment 1, Concentric
Exhibit A2-3-1 Attachment 5 Morningstar DBRS 2025

Preamble:

"Neither OPG's nonregulated generation resources nor the DNNP facilities are covered in this report." (C1-pg-5)… Concentric's analysis specifically excludes consideration of OPG's SMR program, the DNNP, which Concentric understands is intended to be transferred to a separate generator entity in the form of an equity partnership arrangement involving OPG, Canada Growth Fund and Building Ontario Fund.. (C1-pg 9)

"The PRP, however, is anticipated to cost more than double the cost of the DRP and involves a more aged plant, which leads to increased scope and increases risks related to the discovery of additional scope and challenges during the refurbishment process." (C1)

"Darlington's Small Modular Reactor (SMR) Unit 1 is expected to begin commercial operation by the end of 2030. OPG is also planning for three additional SMRs at the Darlington site. On April 4, 2025, the Canadian Nuclear Safety Commission (CNSC) granted OPG a licence to construct one SMR. Issuance of the licence to construct is a key milestone for the SMR project as it shows continued confidence from the Canadian nuclear regulator in OPG executing the SMR project." (A2)

Question(s):

a) Is it OPG or Concentric's view that rating agencies consider the DNNP investments in determining ratings of OPG debt?

b) What portion of the increase in equity returns of 7 basis points (i.e. 45% to 52%) is driven by the PRP? Or does the Concentric report simply rely upon the comparable data of the proxy group for its recommendations at page 78 if the Report?

Response

This response was prepared by Concentric Energy Advisors ("Concentric")

a) Yes, it is Concentric's view that rating agencies consider the DNNP investments, among other factors, in determining OPG's credit ratings. For instance, in its 2025 ratings report, DBRS noted that

> *OPG has a significant capex program under way, with approximately $12.7 billion planned for 2025–26. We note that OPG has started the initial preparation work to refurbish four units at the Pickering GS. The recent granting of the construction licence paves the way for major progress on the Darlington SMR project in the next two or three years. These two projects would be complex undertakings and require significant financing. While capex for both these projects will be regulated and should lead to a substantial increase in the rate base, there is also considerable execution risk, which could lead to large cost overruns.*

S&P, in a 2025 "tear sheet" titled "Ontario Power Generation Inc. License To Build Small Modular Reactor Is Credit Neutral," stated *"[w]e generally view the building of SMRs as negative for credit quality since it entails potential construction risk due to its first-of-its-kind technology. Developing new nuclear power plants is a highly complex project characterized by extensive timelines, significant capital investments, and inherent execution risks that can lead to significant cost overruns and delays."*

Moody's, in a 2025 ratings report on OPG, stated *"[t]he Province recently approved OPG's plan to begin construction on its a CAD20.9 billion small modular reactor (SMR) program at Darlington which carries very high levels of execution risk."*

b) As described in Ex. C1-1-1, Attachment 1, p. 13, Concentric concludes that, taken as a whole, the shift in the Company's risk profile since the time of both EB-2016-0152 and EB-2020-0290 warrants a reassessment of OPG's deemed equity ratio. Concentric did not, however, quantify the explicit risk increments owing to each individual risk factor discussed in its report. Concentric's recommended equity ratio reflects an integrated assessment of OPG's forward-looking business and financial risks and proxy-group evidence; Concentric has not provided (and did not rely on) a project-by-project weighting of how many percentage points of the recommended equity ratio are attributable to the PRP specifically.

Minogi Corp Interrogatory #003

Interrogatory

Reference:

- **Exhibit C2, Tab 1, Schedule 1**

Question(s):

a) Please identify all amounts included in the revenue requirement for 2027–2031 that relate to OPG's funding of, contributions to, or cost recovery associated with nuclear waste management, decommissioning, and/or NWMO-related activities ("**NWMO Activities**").

b) For each amount identified in part a), please describe the extent to which OPG has visibility into, oversight over, or influence on the procurement practices associated with NWMO Activities.

c) Please indicate whether OPG has considered how Ontario or Canadian procurement preferences, as applicable to OPG, are addressed in relation to NWMO Activities reflected in OPG's revenue requirement.

d) Please indicate whether OPG tracks, or plans to track, the extent to which NWMO Activities reflected in OPG's revenue requirement are awarded to First Nation rightsholder businesses located near facilities affected by the work.

e) If the response to part d) is no, please describe any plans or options OPG has considered for tracking such metrics.

Response

a) Refer to Ex. C2-1-1, Table 1 and the discussion at Ex. C2-1-1, Section 4.0.

b) to e)
The Nuclear Waste Management Organization ("NWMO") is a separately incorporated not-for-profit entity under the *Canada Not-For-Profit Corporations Act*, established by electricity-generating companies (member organizations) producing used nuclear fuel, as required by the federal *Nuclear Fuel Waste Act* ("NFWA"). The NWMO's mandate includes the implementation of Canada's plan for the long-term management of used nuclear fuel. The current member organizations of the NWMO are OPG, New Brunswick Power Corporation and Hydro-Québec. The member organizations are required to fund the costs incurred

by the NWMO in respect of its used fuel mandate and do not have the authority to manage or oversee the NWMO's activities, including in the areas of procurement and Indigenous relations. For clarity, pursuant to the *Canada Not-For-Profit Corporations Act* and the NWMO's constating documents, the Board of Directors of the NWMO, despite being appointed by the member organizations, operates independently in their oversight of the NWMO and is under a legal duty to act in good faith with a view to the NWMO's best interests. For these reasons, OPG is not in a position to track the NWMO's procurement activities or metrics.

OAPPA Interrogatory #001

Interrogatory

Reference:
Exhibit C2 / Tab 1 / Schedule 1 / Page 31 of 32

Preamble:

"As OPG has not yet developed comprehensive cost estimates for the future nuclear liabilities, for the DNNP facilities, and none have been recorded in OPG's financial statements, OPG has not reflected any corresponding amounts in the proposed IR term nuclear revenue requirements".

Question(s):

Exhibit C2 / Tab 1 / Schedule 1 / Table 1 reflects OPG's revenue requirement for all its other Nuclear Liabilities, including Bruce which ranges from $270.2 MM in 2027 to $341 MM in 2031.

a) Please explain the absence of this cost information with as much detail and insight as possible.
b) Can you provide any guidance, or outside reference, that might better assist the Board in meeting its requirements under O'Reg 53/05 – specific to ensuring OPG collects its nuclear waste disposal costs for the DNNP - without having any basis for that potential cost, particularly with a new nuclear fuel type and generation technology?
c) Can OPG provide some basis for approximating or estimating the Nuclear Waste management costs for the DNNP? (e.g. estimated by unit – either $/MW or fuel bundle, comparison to known Candu fuel benchmarks, comparison to SMR vs Candu input fuel rates, as a % - or range of % - of the revenue requirements provided in Exhibit C2 / Tab 1 / Schedule 1 / Table 1 for 2027-2031, or, other).

Response

a) The Application does not contain the cost information for the future nuclear liabilities for the DNNP facilities because, as noted at Ex. C2-1-1, p. 31, lines 19-21 it reflects OPG's proposal "that such costs incurred during the IR term […] would be recorded in the [proposed] DNNP Nuclear Liability Deferral Account, which recording would commence once these nuclear liabilities are recognized in OPG's financial statements." In addition to helping limit the breadth and complexity of the current proceeding, this proposal was informed by several factors, including the following:

- As discussed in Ex. C2-1-1, Section 8.0, section 6(2)10.1 of O. Reg. 53/05 requires the OEB to ensure that OPG recovers the costs it incurs in relation to its nuclear liabilities for the DNNP facilities as they are reflected in OPG's audited financial statements approved by OPG's Board of Directors. As discussed in Ex. H1-1-1, Section 7.5, to give effect to this requirement, OPG has proposed to establish the DNNP Nuclear Liability Deferral Account to record the difference between such costs and any associated amounts reflected in the approved revenue requirements.
- As referenced in the preamble, OPG has not yet developed comprehensive cost estimates for these future nuclear liabilities. OPG continues to develop these estimates in conjunction with the next ONFA Reference Plan update, which covers the nuclear liabilities for OPG's existing facilities, to be effective for the 2027-2031 period ("2027 ONFA Reference Plan"). Furthermore, once the baseline lifecycle cost estimates are developed, they must be converted into obligation and expense values in accordance with US GAAP (as described in Ex. C2-1-1, Section 3.1) for purposes of establishing recovery amounts that comply with section 6(2)10.1 of O. Reg. 53/05. The above work is inherently complex and requires significant time and effort, and the results are not expected to be finalized until late 2026.
- The proposed treatment of the future nuclear liabilities costs for the DNNP facilities is analogous to the treatment of the future impacts on the nuclear liabilities costs for OPG's other facilities that will arise from the 2027 ONFA Reference Plan. As discussed in Ex. L-C2-Staff-057, part a), O. Reg. 53/05 requires the OEB to provide for recovery of the revenue requirement impact of the current approved ONFA Reference Plan, and not one that has yet to be completed and approved; as a result, the future impacts of the approved 2027 ONFA Reference Plan for OPG's prescribed facilities will be recorded in the Nuclear Liability Deferral Account.
- The nuclear liabilities costs for the DNNP facilities are expected to commence once DNNP Unit 1 achieves commercial operation, which is planned during October 2030. As such, these costs are expected to be in respect of less than the last 15 months of the 2027-2031 IR term. If the costs are recorded in the DNNP Nuclear Deferral Account as proposed, they would attract no interest under OPG's proposal (which is similar to the treatment of the Nuclear Liability Deferral Account).

Based on the above considerations, and given that its proposal effectively represents an interest-free deferral of ratepayer costs from the last 15 months of the 2027-2031 IR term to subsequent rate periods, OPG determined that it was not necessary to provide any potential cost information related to the nuclear liabilities for the DNNP facilities in the Application.

b) and c)

OPG maintains its proposal with respect to the nuclear liabilities costs for the DNNP facilities as set out in the Application. As explained in part a) above, OPG does not yet have the cost information that it would propose to include in the revenue requirements determined in this Application, nor is it aware of an outside reference or basis that could be used instead. OPG believes its proposal to establish the DNNP Nuclear Liability Deferral Account and record therein, in full, the associated costs incurred during the IR term is reasonable, favours ratepayers and supports regulatory efficiency, while enabling the OEB to meet its requirements under O. Reg. 53/05. OPG will present cost information with respect to the nuclear liabilities for the DNNP facilities in its next payment amounts application. From a rough order of magnitude perspective, OPG anticipates that such revenue requirement impacts should be lower than those in respect of the Bruce facilities set out in this Application.

Board Staff Interrogatory #056

Interrogatory

Reference:
Ref 1: Exhibit C2 / Tab 1 / Schedule 1 / p. 20
Ref 2: Exhibit C2 / Tab 1 / Schedule 1 / Table 2
Ref 3: EB-2007-0905 Decision and Order / p. 88

Preamble:

OPG states that for the 2029-2031 period, the forecast of average unfunded nuclear liability is negative and has been set at $0 for the purposes of the revenue requirement calculation. As such, the full amount of the forecast average asset retirement cost (ARC) earns the proposed weighted average cost of capital.

The OEB-approved recovery methodology provides that return on rate base is calculated based on the lesser of the average unfunded nuclear liability and the average unamortized ARC.

In EB-2007-0905, the OEB adopted this approach to ensure that OPG does not earn its weighted average cost of capital on unfunded nuclear liabilities.

Question(s):

a) Please quantify, for each year from 2029-2031, the revenue requirement impact of applying the $0 unfunded nuclear liability floor compared to the calculated negative unfunded nuclear liability from Reference 2 in the return formula.

b) Please explain why the $0 floor remains appropriate in circumstances where Ontario Nuclear Funds Agreement (ONFA) funds exceed the accounting asset retirement obligation (ARO).
   i. Please confirm whether OPG has considered any alternative treatments for a negative unfunded nuclear liability, e.g. symmetrical adjustment or a sharing mechanism. If not, why not?

c) Please identify the primary drivers causing the unfunded nuclear liability to turn negative in 2029.

d) Based on current ONFA assumptions, is the negative unfunded nuclear liability expected to persist beyond 2031? Please provide a directional forecast.

Response

a) If a floor of $0 were not applied and instead the negative unfunded nuclear liability ("UNL") values were used in the calculation of the revenue requirement impact for OPG's nuclear facilities under the recovery methodology detailed in Ex. C2-1-1, Section 4.1, the proposed revenue requirements would increase as follows: 2029 – $0.3M, 2030 – $0.9M and 2031 – $1.9M.

b) OPG believes that setting the UNL value at $0 when it is negative, rather than using the negative value itself, better accords with the OEB-approved recovery methodology for OPG prescribed facilities' nuclear liabilities costs that was originally established by the OEB in the Decision with Reasons, November 3, 2008 in EB-2007-0905. For example, at page 90 of that decision, in discussing how the UNL construct would be applied as part of the recovery methodology, the OEB stated that the UNL is to be used to determine the "portion of rate base" that would attract a return at the weighted average accretion rate. OPG believes that rate base is intended to be a positive value (or a zero) and therefore a "portion of rate base" should similarly be a positive value (or a zero). For this reason and given that the $0 UNL floor was previously reflected in the revenue requirements approved in EB-2020-0290, while OPG considered using the negative value without a floor, it decided against it.[1] OPG did not consider any other alternative treatments.

c) The UNL is a function of the difference between the asset retirement obligation ("ARO") value and the ONFA segregated funds value. Both the ARO and the segregate funds value are affected by a number of variables (with certain of the variables affecting only one of these two values). For this reason, beyond noting that the ARO for OPG's prescribed facilities is projected to increase by a lower amount than such segregated funds balance in 2029 over 2028, OPG is unable to meaningfully pinpoint the specific drivers causing the UNL to become negative. For additional context, provided below is a brief overview of the main variables underpinning the ARO and the segregated funds, as further discussed in Ex. C2-1-1, Sections 3.1 and 3.2.

   The ARO represents the present value of the committed portion of the costs for OPG's nuclear liabilities, determined using a discount rate established in accordance with US GAAP. The ARO increases due to the passage of time with the unwinding of the present value, through accretion expense, and also with the recognition of variable expenses representing incremental committed costs that arise add additional used nuclear fuel and other nuclear wastes are generated. The ARO decreases due to expenditures made for activities related to nuclear facilities

[1] EB-2020-0290, Ex. C2-1-1, p. 18, lines 8-9; EB-2020-0290 Payment Amounts Order, App. A, Tables 12-15, line 7.

decommissioning and nuclear waste management. The ARO is also adjusted, up or down, from time to time on account of changes in the underlying cost estimates.

The segregated funds value represents the assets set aside to discharge long-term portions of OPG's lifecycle nuclear liabilities pursuant to the Ontario Nuclear Funds Agreement ("ONFA"), as limited by the amount of such underlying funding liability. Segregated funds increase with earnings on the investments and with any funding contributions, and decrease due to fund disbursements that reimburse expenditures OPG makes for eligible activities related to nuclear facilities decommissioning and nuclear waste management. Funding contribution requirements, if any, are adjusted with each approved ONFA Reference Plan and attendant contribution schedule.

d) OPG declines to comment on the unfunded nuclear liability beyond 2031 as it is not relevant to the matters before the OEB in this Application as information beyond the rate period is question is sought.

Board Staff Interrogatory #057

Interrogatory

Reference:
Ref 1: Exhibit C2 / Tab 1 / Schedule 1 / p. 30

Preamble:

OPG reviews and updates the Ontario Nuclear Funds Agreement (ONFA) Reference Plan and associated lifecycle cost estimates and assumptions at least every five years, in line with the ONFA requirements. An updated ONFA Reference Plan is submitted to the Province for review and approval. The next ONFA Reference Plan update, effective for the 2027-2031 period, is under development and is expected to be finalized in late 2026 for the Province's subsequent approval.

The proposed IR term nuclear revenue requirements reflect the approved 2022 ONFA Reference Plan. The corresponding impact of the approved 2027 ONFA Reference Plan will be recorded in the Nuclear Liability Deferral Account for OPG's prescribed facilities and the Bruce Lease Net Revenues Variance Account for the Bruce facilities.

Question(s):

a) Please describe the key assumptions currently under review for the 2027 ONFA Reference Plan that could materially impact asset retirement obligation (ARO), Asset Retirement Costs (ARC), or unfunded nuclear liability (UNL) during the IR term.

b) Please confirm whether any portion of the forecast 2029-2031 negative UNL is sensitive to expected changes in the 2027 ONFA update.

c) Please describe the internal controls to ensure no duplication between Nuclear Liability Deferral Account, the Bruce Lease Net Revenues Variance Account and the Pickering End-of-Life Deferral Account.

Response

a) OPG declines to provide the requested information. O. Reg. 53/05 s. 6(2)8 requires that the "Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the

current approved reference plan."[1] "Approved reference plan" means a reference plan, as defined in the Ontario Nuclear Funds Agreement, that has been approved by the Crown in accordance with the Agreement, as that reference plan may be amended from time to time." (s.01(1)) Such most recent reference plan is the one that has been approved by the Province of Ontario effective January 1, 2022 and that is reflected in the proposed revenue requirements for OPG's nuclear facilities in this Application. As discussed in Ex. C2-1-1, Section 7.0, the ONFA Reference Plan that would be effective January 1, 2027 ("2027 ONFA Reference Plan") is currently under development, with any corresponding revenue requirement impacts for OPG's prescribed facilities arising from such reference plan, once it has been approved by the Province of Ontario, recorded in the Nuclear Liability Deferral Account in accordance with s. 5(2)1 of O. Reg. 53/05.

b) OPG confirms that the UNL, being a function of the difference between the ARO value and the ONFA segregated fund asset value for the prescribed facilities, is expected to be sensitive to changes arising from the 2027 ONFA Reference Plan. The main factors affecting the UNL are summarized in Ex. L-C2-Staff-056 part c), with a number of these typically tied to impacts arising in connection with a new ONFA reference plan, as further discussed in Ex. C2-1-1, Sections 3.1 and 3.2.

c) OPG understands the Pickering End-of-Life Deferral Account to refer to the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account. Internal controls and mechanisms that ensure that there is no duplication of amounts recorded across the Nuclear Liability Deferral Account, the Bruce Lease Net Revenues Variance Account and the Impact Resulting from Optimization of Pickering Station End-of-Life Deferral Account are discussed below.

Internal Controls Over Financial Reporting: OPG makes entries into and maintains the records for each of the three accounts referenced, along with other deferral and variance accounts, through its financial accounting systems and processes. These systems and processes generate financial records that are used to prepare OPG's consolidated financial statements and are therefore subject to a comprehensive suite of typical internal controls over financial reporting (ICFR) necessary to provide the requisite reasonable assurance regarding the reliability of the reporting and the statements prepared. OPG management is required to annually certify that such ICFR are operating effectively under Canadian Securities Administators' National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*. These same ICFR also provide such assurance over the balances recorded in the company's deferral and variance accounts, as part of the financial statements.

[1] For purposes of the regulation, "nuclear decommissioning liability" means "OPG's liability for decommissioning its nuclear generation facilities and management of its nuclear waste and used fuel." (s. 0.1(1))

External Audits: OPG's annual consolidated financial statements, which include the effects of the Company's regulatory assets and regulatory liabilities in respect of its deferral and variance accounts, are audited, with an additional audit conducted specifically for the deferral and variance account balances when they are brought forward for disposition. OPG's 2024 audited consolidated financial statements and associated independent auditor's opinion can be found at Ex. A2-1-1, Attachment 4 and the audited deferral and variance account balances as at December 31, 2024 and associated independent auditor's opinion can be found at Ex. H1-1-1, Attachments 1 and 2. Both of these opinions are unqualified.

Established Methodologies and Internal Reviews: All entries made into the accounts comply with the EB-2020-0290 Payment Amounts Order and O. Reg. 53/05, including with respect to any reference amounts relative to which the additions are determined, and use established methodologies to derive account additions as described in Ex. H1-1-1, Sections 5.14, 5.16 and 5.23, respectively. The Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account have been in existence since OPG's first payment amounts proceeding, EB-2007-0905, and the methodologies used to derive such entries have been subject to review across multiple prior proceedings. While the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account was first established in EB-2020-0290, as noted at the above evidence, the methodology used to derive the entries is the same as used for the previously authorized Impact Resulting from Changes to Pickering Station End-of-Life Dates (2017) Deferral Account and the resulting impacts recorded in the account were very close to such entries forecast in EB-2020-0290. The detailed calculations of the 2023 and 2024 additions to each of the three accounts are set out in Ex. H1-1-1, Tables 17, 10 and 18-19, respectively. The calculations are subject to several levels of internal review by OPG subject matter experts, with an additional review performed each time an account disposition request is made with the OEB.

Delineation through Scope, Data and Methodological Controls: As Ex. H1-1-1 demonstrates, each of the three accounts have a distinct scope, capture different impacts and are specifically delineated through their methodologies. For example, the Bruce Lease Net Revenues Variance Account is limited to impacts related to OPG's revenues associated with the Bruce lease and related agreements and its costs associated with the Bruce nuclear generating stations, while the other two accounts capture certain impacts for OPG's prescribed facilities only. The EB-2020-0290 Payment Amounts Order set out the reference amounts for the Bruce Lease Net Revenues Variance Account, while OPG's financial records separately maintain each of such actual revenues and costs. With respect to nuclear liability related impacts specifically, Ex. C2-1-1 describes how financial information is delineated for each of the nuclear stations, with Ex. C2-1-1, Tables 2 and 3 illustrating such delineation between the prescribed facilities and the Bruce

facilities. As the Bruce Lease Net Revenues Variance Account captures all differences in the above noted revenues and costs, no further segregation protocols are required for these elements for the Bruce facilities.

Both the Nuclear Liability Deferral Account and the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account relate to OPG's prescribed facilities, and both capture nuclear liability related impacts. The methodological controls to addressing the interaction between such impacts recorded across the two accounts are discussed below. The Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account also records certain non-ARC impacts resulting from changes in Pickering end-of-life dates for accounting purposes. OPG's fixed asset accounting system maintains separate ARC accounts, by nuclear station, which enables distinct reporting related to these costs and their depreciation, informing the associated account entries.

To ensure there is no duplication in respect of the nuclear liability related impacts across the Nuclear Liability Deferral Account and the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account, the account methodologies compute revenue requirement impacts on an incremental basis for each underlying triggering event that is within the respective account's scope. Depending on the nature of the triggering event, this involves measuring the event's outcome against the corresponding forecast variables underpinning the approved revenue requirements or entries recorded in the other account, and then, as needed based on the sequence of additions across the two accounts, eliminating any resulting impacts that are already captured by the other account.

With respect to the 2023 and 2024 additions, there are three overlapping triggering events in scope of the Nuclear Liability Deferral Account or the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account. They are: the year-end 2020 ARO/ARC adjustment and depreciation change reflecting the revised Pickering Units 1 and 4 accounting end-of-life date; the year-end 2021 ARO/ARC adjustment and depreciation change reflecting the impact of the 2022 ONFA Reference Plan and the subsequent impact of the 2022 ONFA Contribution Schedule; and the year-end 2023 ARO/ARC adjustment and depreciation change reflecting the revised Pickering Units 5-8 accounting end-of-life date. The manner in which the account methodologies function to specifically eliminate any duplication in respect of these events is outlined in Ex. H1-1-1.[2]

[2] For example, see Ex. H1-1-1: p. 48, lines 9-15; Table 18a, Notes 2 and 4; Table 18b, Note 6; Table 19a, Note 1; and Table 19b, Notes 4 and 6.

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Reference:
Ref 1: Exhibit C2 / Tab 1 / Schedule 1 / p. 30
Ref 2: Exhibit C2 / Tab 1 / Schedule 1 / Table 2
Ref 3: Exhibit C2 / Tab 1 / Schedule 1 / Table 3

Preamble:

OPG extended the accounting end of life (EOL) for Pickering Units 5-8 to 2070, resulting in an increase in prescribed asset retirement obligation (ARO) of $598.5 million and a decrease in the Bruce ARO of $438.7 million. The tables in Reference 2 and Reference 3 provide the revenue requirement impact of the extension.

Question(s):

a) Please provide a reconciliation of how the Pickering End of Life (EOL) extension affects the unfunded nuclear liability for prescribed facilities in 2027-2031.

b) Please confirm whether the allocation methodology for central nuclear programs has changed since EB-2020-0290. If so, describe the changes and their quantitative impact.

Response

a) Please see Attachment 1 for the requested reconciliation of the unfunded nuclear liability for the prescribed facilities. OPG notes that the unfunded nuclear liability amounts for the "Without Change in Pickering End-of-Life Date" scenario at Table 1, line 20, cols. (f)-(j) of Attachment 1 are shown before the application of the $0 floor, whereas these amounts are shown after the application of the $0 floor in Ex. C2-1-1, Table 5a, Note 3, col. (b). The $0 floor is further discussed in Ex. L-C2-Staff-056.

b) OPG confirms that there have been no changes to the allocation methodology for central nuclear waste management programs since EB-2020-0290.

Numbers may not add due to rounding.

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Exhibit L
C2-Staff-058
Attachment 1
Table 1

Table 1
Change in Pickering End-of-Life Date to 2070 Impact on Unfunded Nuclear Liability Balance ($M)
Years Ending December 31, 2027 to 2031

Line No.	Description	With Change in Pickering End-of-Life Date[1] 2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	Without Change in Pickering End-of-Life Date[2] 2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	Impact 2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k) = (a) - (f)	(l) = (b) - (g)	(m) = (c) - (h)	(n) = (d) - (i)	(o) = (e) - (j)
	ASSET RETIREMENT OBLIGATION															
1	**Opening Balance**	13,448.3	13,515.2	13,715.1	14,040.7	14,389.0	12,911.3	12,975.8	13,176.8	13,506.6	13,865.1	537.0	539.4	538.3	534.1	523.9
2	**Used Fuel Storage and Disposal Variable Expenses**	26.8	38.5	38.0	50.2	54.2	41.9	59.4	57.7	74.8	79.5	(15.1)	(20.9)	(19.7)	(24.6)	(25.3)
3	**Low & Intermediate Level Waste Management Variable Expenses**	3.6	8.7	20.9	22.7	24.9	4.7	11.0	28.0	29.9	32.3	(1.1)	(2.3)	(7.1)	(7.2)	(7.4)
4	**Accretion Expense**	673.9	691.8	704.6	718.7	724.9	655.3	669.8	682.0	697.1	705.5	18.6	22.0	22.6	21.6	19.4
5	**Expenditures for Used Fuel, Waste Management & Decommissioning**	(637.4)	(539.1)	(437.9)	(443.3)	(472.1)	(637.4)	(539.1)	(437.9)	(443.3)	(472.1)	0.0	0.0	0.0	0.0	0.0
6	**Consolidation and Other Adjustments**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	**Closing Balance Before Year-End Adjustments** (lines 1 through 6)	13,515.2	13,715.1	14,040.7	14,389.0	14,720.9	12,975.8	13,176.8	13,506.6	13,865.1	14,210.3	539.4	538.3	534.1	523.9	510.6
8	**2022 ONFA Reference Plan Adjustment**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	**Year-End 2020 and 2023 Adjustment Reflecting Nuclear Station End of Life Changes**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Closing Balance** (line 7 through 9)	13,515.2	13,715.1	14,040.7	14,389.0	14,720.9	12,975.8	13,176.8	13,506.6	13,865.1	14,210.3	539.4	538.3	534.1	523.9	510.6
11	**Average Asset Retirement Obligation** ((line 1 + line 7)/2)	13,481.8	13,615.2	13,877.9	14,214.9	14,555.0	12,943.5	13,076.3	13,341.7	13,685.8	14,037.7	538.2	538.9	536.2	529.0	517.3
	NUCLEAR SEGREGATED FUNDS BALANCE															
12	**Opening Balance**	13,298.6	13,464.7	13,719.5	14,062.2	14,443.6	13,298.6	13,464.7	13,719.5	14,062.2	14,443.6	0.0	0.0	0.0	0.0	0.0
13	**Earnings (Losses)**	664.3	674.9	689.9	708.1	727.3	664.3	674.9	689.9	708.1	727.3	0.0	0.0	0.0	0.0	0.0
14	**Contributions**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15	**Disbursements**	(498.2)	(420.1)	(347.2)	(326.7)	(342.0)	(498.2)	(420.1)	(347.2)	(326.7)	(342.0)	0.0	0.0	0.0	0.0	0.0
16	**Closing Balance** (line 12 through 15)	13,464.7	13,719.5	14,062.2	14,443.6	14,828.9	13,464.7	13,719.5	14,062.2	14,443.6	14,828.9	0.0	0.0	0.0	0.0	0.0
17	**Average Nuclear Segregated Funds Balance** ((line 12 + line 16)/2)	13,381.7	13,592.1	13,890.8	14,252.9	14,636.3	13,381.7	13,592.1	13,890.8	14,252.9	14,636.3	0.0	0.0	0.0	0.0	0.0
	UNFUNDED NUCLEAR LIABILITY BALANCE (UNL)															
18	**Opening Balance** (line 1 - line 12)	149.7	50.5	(4.4)	(21.5)	(54.6)	(387.4)	(489.0)	(542.7)	(555.6)	(578.5)	537.0	539.4	538.3	534.1	523.9
19	**Closing Balance** (line 7 - line 16)	50.5	(4.4)	(21.5)	(54.6)	(108.0)	(489.0)	(542.7)	(555.6)	(578.5)	(618.6)	539.4	538.3	534.1	523.9	510.6
20	**Average Unfunded Nuclear Liability Balance** ((line 18 + line 19)/2)	100.1	23.0	(12.9)	(38.0)	(81.3)	(438.2)	(515.8)	(549.1)	(567.0)	(598.6)	538.2	538.9	536.2	529.0	517.3

Notes:
1 From Ex. C2-1-1, Table 2

2 "Without Change in Pickering Station End-of-Life Date" amounts are presented for illustrative purposes and are derived from a base case using the same assumptions for baseline cost estimates, discount rates and end-of-life dates as those underlying amounts reflected in this application, with the exception of the Pickering end-of-life date change to 2070 effective December 31, 2023.