CAPITAL STRUCTURE AND RETURN ON EQUITY

1.0 PURPOSE

This evidence describes the methodologies that OPG and DNNP LP have used to determine their respective capital structure and return on equity ("ROE") proposals for the IR term.

2.0 CAPITAL STRUCTURE

2.1 OPG Capital Structure

OPG is seeking approval of the IR term cost of capital for its regulated business, as presented in Ex. C1-1-1, Tables 1-5. 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. The engagement letter executed with Concentric Energy Advisors is filed as Attachment 2 to this exhibit.

The proposed capital structure reflects the material increase in OPG's business risks. As OPG is undertaking multiple complex projects simultaneously to meet increasing electricity demand in alignment with the Province's Integrated Energy Plan, over the IR term, OPG will experience heightened risks primarily related to: execution of major projects such as the Pickering Refurbishment Program and hydroelectric refurbishments and redevelopments, the continued shift of OPG's rate base to riskier nuclear assets during a period of lower output over which to recover these costs, and funding and credit rating risks, among others. Concentric also found that OPG's risk is significantly elevated relative to the proxy groups, as OPG is a pure generation utility with significant nuclear concentration and its nuclear revenue is entirely subject to output variability, all of which distinguishes it from other regulated utilities. Concentric found that such proxy groups for OPG have a mean and median equity ratio ranging from 50% to 53%. OPG expects to receive a shareholder equity injection from the Province of Ontario totalling $5 billion over the 2025-2027 period.

The debt component of OPG's capital structure is described in Ex. C1-1-2 and Ex. C1-1-3 for long-term and short-term debt, respectively. OPG's capitalization and cost of capital for the 2020-2031 period is summarized in Ex. C1-1-1, Tables 1-12. OPG has applied this capitalization to the rate base, as adjusted to reflect the application of the "lesser of Asset Retirement Costs and Unfunded Nuclear Liabilities" provision, as in prior OPG applications, as part of the cost recovery methodology for the nuclear liabilities for OPG's prescribed facilities (refer to Ex. C2-1-1).

2.2 DNNP LP Capital Structure

Section 13.(1) of Ontario Regulation 53/05 establishes the 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.

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. This proposed capital structure for DNNP LP is supported by the expert testimony of Mr. Cliff Inskip of Polar Star Advisory provided in Attachment 3 to this exhibit. The engagement letter executed with Polar Star Advisory is filed as Attachment 4 to this exhibit.

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."[1] With an anticipated October 2030 in-service date[2] for DNNP facilities Unit 1 and the IR term that ends on December 31, 2031, the Application is requesting a 100% equity funded capital structure for a period of Unit 1 in-service operation that falls within the time frame during which Mr. Inskip has opined there is a low to very low probability of a successful

[1] Ex. C1-1-1, Attachment 3, p. 34.
[2] As detailed in Ex. D2-4-6, the High Confidence Schedule is targeting an operating Unit 1 facility by October 17, 2030.

non-recourse investment grade bond issue. In the unlikely event that DNNP LP were successful in raising such financing during the IR term, the difference between the revenue requirement impact of the actual financing and the 100% equity funded capital structure underpinning payment amounts would be recorded in the DGCSVA. The DGCSVA is discussed further in Ex. H1-1-1.

3.0 RETURN ON COMMON EQUITY FOR IR TERM

The Application incorporates an ROE of 9.11% for OPG[3] 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 Application proposes to establish the ROE for OPG and DNNP LP for the IR term using the prevailing ROE specified by the OEB in accordance with the OEB's EB-2024-0063 decision as of the effective date of the Payment Amounts Order in this proceeding. Consistent with prior OPG proceedings, the Application proposes to use the same ROE throughout the IR term.

[3] Consistent with EB-2020-0290 Decision and Order dated November 15, 2021, Schedule A, p. 23, a portion of rate base continues to be financed by common equity that is subject to return at the long-term debt rate until the end of 2036.

LIST OF ATTACHMENTS

Attachment 1: Ontario Power Generation Common Equity Ratio Study by Concentric Energy Advisors

Attachment 2: Executed Engagement Letter for Concentric Energy Advisors

Attachment 3: Initial Financing for Darlington New Nuclear Program Expert Testimony by Cliff Inskip

Attachment 4: Executed Engagement Letter for Polar Star Advisory

ONTARIO POWER GENERATION

Common Equity Ratio Study

DECEMBER 2025

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Section 1:

INTRODUCTION

A. Scope of Analysis and Overview of Ontario Power Generation

Concentric Energy Advisors, Inc. ("Concentric") was retained to prepare this independent report as to whether the application of the cost of capital approved by the Ontario Energy Board ("OEB" or the "Board") in EB-2020-0290 is an appropriate basis for setting payment amounts in Ontario Power Generation's ("OPG") next rates application. Consistent with the OEB's findings in EB-2024-0063, Concentric's analysis focuses on OPG's deemed capital structure.

1. Overview of OPG and its Regulatory Framework

OPG is an electricity generation company established under the Ontario Business Corporations Act and is wholly owned by the Province of Ontario (the "Province"). OPG's regulated facilities are the prescribed facilities under Ontario Regulation 53/05 ("O. Reg. 53/05"). As of December 31, 2024, OPG's regulated generation portfolio comprised two nuclear generating stations (i.e., the Pickering Nuclear Generation Station ("Pickering") and the Darlington Nuclear Generation Station ("Darlington")) as well as 54 hydroelectric generating stations across the province. This geographically diverse regulated hydroelectric fleet has a total capacity of 6,566 MW as of December 31, 2024, with an average age of approximately 90 years.

The Pickering and Darlington generating stations have a combined capacity of 5,576 MW and each have four operating units, including the last Darlington unit currently in refurbishment and scheduled to return to service in 2026. The four operating Pickering units are scheduled to be shut down for refurbishment in September 2026 and return to service between 2031 and 2034. Each refurbishment is intended to enable 30-plus years of additional operating life. OPG also owns four Pickering units that have been permanently shut down and have been or are being placed in a safe state for future decommissioning.

OPG's regulated generating stations provide electricity into the wholesale energy market and revenues are based on regulated prices determined by the OEB.

Aside from the prescribed facilities, OPG also owns and operates a number of non-regulated generation resources. Additionally, OPG is progressing the execution of the first-of-a-kind Darlington New Nuclear Program ("DNNP") beginning with the first of four planned small modular reactors ("SMRs"), scheduled to enter commercial operation in 2030. Concentric understands that the DNNP 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. Neither OPG's non-regulated generation resources nor the DNNP facilities are covered in this report.

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.

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.

The regulated rates that are established by the OEB for OPG's prescribed facilities typically comprise base regulated rates and any applicable rate riders for recovery or repayment of approved deferral and variance account balances.

OPG has credit ratings from Morningstar DBRS ("DBRS," A (low), April 2025[1]), S&P Global Ratings ("S&P," BBB+, August 2024[2]), and Moody's Ratings ("Moody's," A3, June 2025[3]).

2. Concentric's Approach

In preparing this report, Concentric:

1. Performed a company-focused assessment of changes in OPG's business and financial risks since EB-2016-0152 (i.e., the last rates application in which the OEB performed a Fair Return Standard ("FRS") assessment of OPG's cost of capital) and EB-2020-0290 (i.e., OPG's previous application, in which a settlement was achieved) and on a forward-looking basis;

1 Morningstar DBRS, "Ontario Power Generation Inc.," April 21, 2025.
2 S&P Global Ratings, "Ontario Power Generation Inc.," August 14, 2024.
3 Moody's Ratings, "Ontario Power Generation Inc.," June 30, 2025.

2. Performed a market/industry assessment of industry trends and peer group companies, including an examination of the actual and authorized capital structures for a proxy group of reasonably comparable companies; and
3. Determined an appropriate capital structure for OPG for recommendation to the OEB.

B. Overview of Concentric

Concentric is a management consulting and economic advisory firm, focused on the North American energy industry. Based in Marlborough, Massachusetts, and with offices in Washington, D.C., and Calgary, Alberta, Concentric specializes in regulatory and litigation support, transaction-related financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses. The firm provides financial, economic and regulatory advisory services to clients across North America, including utility companies, regulatory and public agencies, and utility sector investors. Concentric has advised energy industry participants on the purchase and sale of nuclear facilities, hydroelectric facilities, and other generation assets, and we have served in an independent monitoring or project advisory function on major capital projects at several nuclear generating units in North America. Concentric also has experience relating to major refurbishment work on nuclear power life cycle management and extended power uprates in the U.S. and Canada. Concentric has provided expert testimony on the cost of capital in more than 100 regulatory proceedings in Canada and the U.S. over the past five years.

C. Introduction of Witness

Daniel Dane, President at Concentric, authored this report with assistance from other Concentric staff. Mr. Dane is a senior expert who provides testimony before Canadian provincial and U.S. state agencies on matters pertaining to economics and finance in the energy industry. He regularly advises utilities, generating companies, public agencies and institutional investors on business issues pertaining to the utilities industry. This work includes determining the cost of capital for the purpose of ratemaking and providing expert testimony and studies on matters pertaining to incentive regulation, rate policy, valuation, and capital costs. He has advised both buyers and sellers in numerous transactions involving hydroelectric, nuclear, fossil and renewable generation facilities, and worked with companies to develop strategies for acquiring these assets. He has testified or provided expert evidence before state and provincial regulators across Canada and the U.S., including the OEB. This work has been provided on behalf of utilities, regulatory commissions and staff. Mr. Dane also coauthored "A Comparative Analysis of Return on Equity of Natural Gas Utilities" with

Concentric colleagues on behalf of the OEB. Mr. Dane appeared as a witness on cost of capital matters on behalf of OPG in EB-2016-0152 and EB-2020-0290, on behalf of Enbridge Gas, Inc. in EB-2022-0200, and on behalf of a coalition of Ontario utilities in EB-2024-0063.

Mr. Dane has an MBA from Boston College in Chestnut Hill, Massachusetts and a BA in Economics from Colgate University in Hamilton, New York. Mr. Dane is a certified public accountant, licensed in the Commonwealth of Massachusetts.

Mr. Dane's qualifications are detailed more fully in Appendix D.

D. Witness Duty

I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

a. to provide opinion evidence that is fair, objective and non-partisan;
b. to provide opinion evidence that is related only to matters that are within my area of expertise; and
c. to provide such additional assistance as the OEB may reasonably require, to determine a matter in issue.

I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

E. Report Organization

The remainder of this report is organized as follows:

Section II provides an executive summary of Concentric's findings and recommendations.

Section III summarizes the Fair Return Standard and the principles of a fair return.

Section IV provides Concentric's company-focused assessment of changes in OPG's business and financial risks, and factors that impact OPG's access to capital and financial integrity.

Section V provides Concentric's evaluation of cost recovery and capitalization approaches taken in other North American jurisdictions that have or are investing in large nuclear plant construction projects to provide context for OPG's legislative and regulatory support. This section also provides Concentric's review of steps that North American regulators are taking to address cost and risk pressures due to the increased forecast demand, and an increased focus on energy security and reliability.

Section VI continues Concentric's market/industry assessment, describing the Fair Return Standard analysis that Concentric performed in order to evaluate the appropriate deemed capital structure for OPG given the Company's business and financial risks relative to the peer group companies.

Section VII summarizes our key conclusions and recommendations.

Section 2:
EXECUTIVE SUMMARY

A. Purpose of Report

The purpose of this report is to provide Concentric's findings and recommendations regarding an appropriate cost of capital for OPG in its next rate application, which will cover the five-year period from 2027 to 2031 (i.e., the "IR Term").[4] 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.

Concentric's analysis and conclusions are focused on whether the current cost of capital for OPG, inclusive of the capital structure, adheres to the FRS. The FRS, as recently reaffirmed by the OEB in EB-2024-0063,[5] 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
- At a level that is comparable to returns required on investments of similar risk (the "comparability" standard).

These standards must be met individually and collectively to satisfy the FRS, and no one ranks as more important than another. Important to an evaluation of the cost of capital are also the concepts of risk and opportunity cost. As stated in <u>Fundamentals of Corporate Finance</u>:

> *We will henceforth use the terms required return, appropriate discount rate, and cost of capital more or less interchangeably because, as the discussion in this section suggests, they all mean essentially the same thing. The key fact to grasp is that the cost of capital associated with an investment depends on the risk of that investment. This is one of the*

4 Brief summaries of OPG's previous rates applications and the 2024 generic cost of capital proceeding are provided in Appendix A.
5 EB-2024-0063, Decision and Order, March 27, 2025, at 4 and 34.

> *most important lessons in corporate finance, so it bears repeating: The cost of capital depends primarily on the use of the funds, not the source.*[6]

As such, the FRS considers both company-specific factors, focused on the risk profile of a Company, which affects its ability to maintain its financial integrity and attract capital, and market/industry factors, focused on investor perspectives and whether the authorized cost of capital provides a return that is commensurate with returns on other similarly-risked investments. An FRS analysis, therefore, involves analyzing the business and financial risks specific to the business, as well as the views of the market, business risks and financial risks facing comparable investments.

In EB-2024-0063, the OEB updated its cost of capital framework, 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."[7] This 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.

B. Company-Focused Assessment: OPG's Business and Financial Risk

An internal assessment is key to understanding whether and how OPG's business and financial risks have changed over time. Concentric's internal assessment focuses on: (a) changes to OPG's business and financial risks since EB-2016-0152 and EB-2020-0290; (b) expected changes to OPG's risk profile on a forward-looking basis, consistent with how an investor would analyze OPG; and (c) evidence regarding OPG's credit ratings and other independent investor viewpoints. Because OPG's regulated capital structure is reflective of its overall risk profile related to the regulated operations of the Company, Concentric's analysis considered both the regulated nuclear and hydroelectric businesses and their attendant risks.

With regard to the company-focused assessment, Concentric reaches the following summary conclusions.

- Demand for electricity in Ontario is projected to increase by 65% by 2050 as compared to 2026.[8] In addition, in June 2025, Ontario released "Energy for Generations," Ontario's first integrated energy plan (the "Integrated Energy Plan"). The Integrated Energy Plan discusses

6 Stephen A. Ross, Randolph W. Westerfield, and Bradford D. Jordan, *Fundamentals of Corporate Finance*, 5th ed. (New York: Irwin McGraw-Hill, 2000), at 419.
7 EB-2024-0063, Decision and Order, March 27, 2025, at 35.
8 IESO, 2026 Annual Planning Outlook: 2026 Demand Forecasts, November 18, 2025, at 8.

the drivers of growing demand for electricity, and OPG's nuclear refurbishments are featured prominently in the strategy to meet that demand.

- While the OEB has previously found that OPG's nuclear business is riskier than its hydroelectric business, the OEB has established one uniform capital structure that applies to both OPG's nuclear and its hydroelectric revenue requirements. Further, the OEB found that a change in the mix between nuclear and hydroelectric rate base can affect OPG's overall risk profile.[9] In the upcoming rate period, OPG's regulated asset mix will continue to shift towards a higher proportion of nuclear assets. By 2031, nuclear generation operations (excluding DNNP) are projected to comprise approximately 66% of OPG's overall regulated rate base, compared to 31% as of December 31, 2016, 35% as of December 31, 2019, and 63% as of December 31, 2026. This factor by itself indicates a significant shift in OPG's risk profile.
- One of the drivers of this increased nuclear focus is that OPG is entering a period of unprecedented capital investment. Specifically, excluding DNNP, OPG forecasts approximately $28.0 billion in capital spend for its regulated nuclear and hydroelectric businesses in the 2027-2031 timeframe. This compares to a currently forecast $15.2 billion in capital spend in the 2022-2026 period and $8.1 billion in capital spend in the 2017-2021 period. Put simply, expansive capital programs that are headlined by "mega projects" such as the Pickering Refurbishment Project ("PRP") increase both business and financial risk for regulated utilities such as OPG.
- In this upcoming rate period, OPG will embark on the execution of the PRP, an approximately $26.8 billion-dollar project (approximately $18.1 billion in the 2027-2031 timeframe) to refurbish Units 5-8 at Pickering. 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. In addition, the PRP's schedule, major scope differences, layup period and site location all increase the risk relative to the DRP.

[9] For instance, in its decision in EB-2013-0321 (at 114), the OEB found "the Board has determined that business risk has changed for this payment setting period, and that the business risk is reduced. The business risk is reduced because of the addition of significant hydroelectric assets to rate base, which are less risky than nuclear assets."

- At the time of EB-2020-0290, OPG's hydroelectric construction and operations work were not a major source of incremental risk compared to the Company's prior rate application (i.e., EB-2016-0152). That is no longer the case as OPG endeavors to complete significant hydroelectric power plant refurbishments and, in some cases, redevelopments across a number of aging facilities, with approximately $4.8 billion in capital expenditures planned in the 2027-2031 timeframe.

- 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, as will the Company's risks related to cyber security.

- OPG is subject to rate regulation, which decreases cost recovery risk for the Company relative to if it were a non-regulated entity. A utility's regulatory framework is an important consideration for both equity and debt investors, and utility regulation is generally found by rating agencies and investors to decrease risk, all else equal, compared to competitive ventures. As stated by S&P, "[u]tility regulation, no matter where on the continuum of our assessments, strengthens a utility's business risk profile, and generally underpins our ratings."[10] In addition, the proposed implementation of concurrent cost recovery ("CCR") of interest costs on construction work in progress ("CWIP") for the PRP pursuant to an amended Ontario Regulation 53/05 (i.e., 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. 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, Concentric'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.

- 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. 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. This is because each MWh of nuclear generation will become more financially valuable to OPG as the nuclear

10 S&P Global, North American Utilities Regulatory Jurisdictions Update: Connecticut And Mississippi Assessments Revised, Other Notable Developments, February 19, 2025, at 2.

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. In fact, OPG forecasts to produce just 126 TWh from nuclear sources in the 2027-2031 rate period, a 28% decrease from the 2022-2026 total of 175 TWh and a more than 39% decrease from the 2017-2021 historical total of 209 TWh, while simultaneously investing in the refurbished units at Pickering.

- Financially sound utilities have access to capital by virtue of their regulated business model. The "capital attraction" component of the FRS doesn't simply relate to access to capital, but also to the ability to access capital *at a reasonable cost*. OPG's access to capital is due in part to OPG's provincial ownership, which results in a three notch credit rating "uplift" relative to OPG's stand-alone credit profile. OPG also operates pursuant to rate regulation, which is credit supportive. 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.
- In terms of the "financial integrity" component of the FRS, OPG's financial risk will increase in the period from 2026 to 2031, as illustrated by the pressure on, and potential decline below current credit rating thresholds of, key credit metrics during the IR Term.

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.

C. Market/Industry Assessment: Industry Trends and Peer Group Analysis

A market/industry assessment from a cost of capital perspective focuses squarely on the "comparability" component of the FRS. Concentric's market/industry assessment provides context for trends in the electricity industry related to energy security and reliability, electrification and increasing electricity demand that are impacting electric utilities across North America. These trends are resulting in record levels of capital investment that require significant flows of capital to regulated utilities.

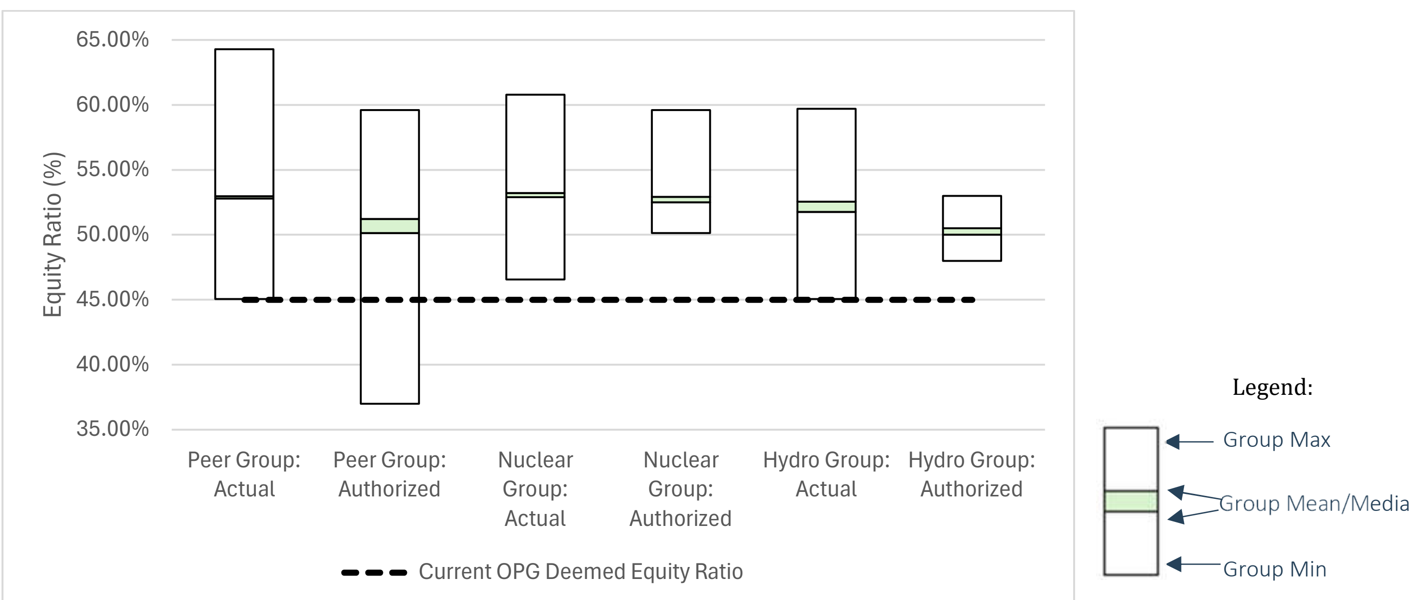
Because OPG has been and will continue to be competing for capital as the North America energy industry navigates these sector-wide trends, its authorized cost of capital needs to be commensurate with returns available to peers of similar risk. Despite provincial ownership, it is not possible for OPG to operate or raise capital in isolation from the broader North American market for capital.

In terms of the comparable return requirement of the FRS, Concentric conducted a series of screens based on OPG's operational profile to narrow down all publicly-traded North American investor-owned utility companies to those with similar operating characteristics to OPG. In doing so, Concentric compiled four proxy groups: (1) a main peer group; (2) a "nuclear" group; (3) a "hydroelectric" group; and (4) a peer group of utilities that operate in Standard & Poor's "most credit supportive" jurisdictions. The latter three peer groups are subsets of the first group that allow for an assessment of the impact of focusing on a relevant risk variable.

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.

Figure 1, below, provides summary statistics from the above-described peer groups, and shows the positioning of OPG's current deemed equity ratio relative to those statistics.

Figure 1: Summary Statistics for Peer Groups



As shown in Figure 1, the average range of equity ratios is from 49.30% to 52.97%, and the medians range from 50.00% to 53.23%. The upper bound for the proxy group results ranges from 53.00% to 64.29%.

OPG's current deemed equity ratio of 45% is nearly 5% to 8% below the mean and median results, and 8% to over 19% below the upper end of the range of results. As discussed above, we believe OPG falls toward the upper end of the risk spectrum, reasonably supporting an equity ratio of 53% or higher to as much as 65% (*i.e.*, at the upper end of the proxy group results).

For this upcoming rate setting period, however, Concentric conservatively recommends an equity ratio of no less than 52% for OPG. 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. This recommendation balances considerations related to OPG's heightened risk profile and proxy group position with the Board's findings in EB-2016-0152 and EB-2024-0063, as discussed herein.

Section 3:
PRINCIPLES FOR A FAIR RETURN

A. Overview of Legal Requirements

The principles surrounding the concept of a "fair return" for a regulated company were established by the Supreme Court of Canada in the *Northwestern Utilities v. City of Edmonton* (1929) ("Northwestern") case, where the Supreme Court found:

> *By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.*[11]

More recently, the Supreme Court of Canada in *Ontario (Energy Board) v. Ontario Power Generation Inc.* confirmed *Northwestern*, stating:

> *This means that the utility must, over the long run, be given the opportunity to recover, through the rates it is permitted to charge, its operating and capital costs ("capital costs" in this sense refers to all costs associated with the utility's invested capital). This case is concerned primarily with operating costs. If recovery of operating costs is not permitted, the utility will not earn its cost of capital, which represents the amount investors require by way of a return on their investment in order to justify an investment in the utility. The required return is one that is equivalent to what they could earn from an investment of comparable risk. Over the long run, unless a regulated utility is allowed to earn its cost of capital, further investment will be discouraged and it will be unable to expand its operations or even maintain existing ones. This will harm not only its shareholders, but also its customers.*[12]

The law regarding a fair return for utility cost of capital in the United States has evolved similarly. The U.S. Supreme Court set out guidance in the bellwether cases of *Bluefield Water Works* and *Hope Natural Gas Co.* as to the legal criteria for setting a fair return. In *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia*[13], the Court recognized that a rate of return may become unreasonable due to changing market conditions:

> *The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical*

11 Northwestern, p. 193.
12 Ontario (Energy Board) v. Ontario Power Generation Inc. 2015 SCC 44, at para 16.
13 *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679, 693 (1923).

> *management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.*[14]

The U.S. Supreme Court further elaborated on this requirement in its decision in *Federal Power Commission v. Hope Natural Gas Company*[15]. The Court emphasized the role of risk in this analysis and described the relevant criteria as follows:

> *From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock.... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.*[16]

With the passage of time, the Fair Return Standard has been interpreted many times in both Canada and the U.S. For example, the National Energy Board ("NEB", now the "CER") summarized its interpretation of the "Fair Return Standard" in its RH-2-2004 Phase II Decision and reiterated that interpretation in its *Trans Québec & Maritimes Pipelines Inc.* RH-1-2008 Decision.

> *The Board is of the view that the Fair Return Standard can be articulated by having reference to three particular requirements. Specifically, a fair or reasonable return on capital should: be comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment standard); enable the financial integrity of the regulated enterprise to be maintained (the financial*

14 *Id.*, at 679.
15 *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).
16 *Id.*, at 591.

> *integrity standard); and permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).*
>
> *In the Board's view, the determination of a fair return in accordance with these enunciated standards will, when combined with other aspects for the Mainline's revenue requirement, result in tolls that are just and reasonable.*[17]

All three standards must be met, and none ranks in priority to the others. To that point, the OEB articulated the legal requirements for satisfying the Fair Return Standard in Canada in its 2009 Report as follows:

> *The Board affirms its view that the Fair Return Standard frames the discretion of a regulator, by setting out the three requirements that must be satisfied by the cost of capital determinations of the tribunal. Meeting the standard is not optional; it is a legal requirement. Notwithstanding this obligation, the Board notes that the Fair Return Standard is sufficiently broad that the regulator that applies it must still use informed judgment and apply its discretion in the determination of a rate regulated entity's cost of capital.*[18]

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> *… all three standards or requirements (comparable investment, financial integrity, and capital attraction) must be met and none ranks in priority to the others. The Board agrees with the comments made to the effect that the cost of capital must satisfy all three requirements which can be measured through specific tests and that focusing on meeting the financial integrity and capital attraction tests without giving adequate consideration to the comparability test is not sufficient to meet the [Fair Return Standard].*[19]

Importantly, the Fair Return Standard applies both to the authorized ROE and the deemed capital structure.

The OEB confirmed these principles in EB-2024-0063.[20]

17 National Energy Board RH-2-2004 Reasons for Decision, TransCanada PipeLines Ltd, Phase II, April 2005, p. 17.
18 Ontario Energy Board, EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, p. i.
19 *Id., at* 19.
20 EB-2024-0063, Decision and Order, March 27, 2025, at 4.

B. Stand-Alone Principle

The stand-alone principle provides 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. In this way, capital is efficiently allocated, with each business segment earning a return based on its own unique risks and business characteristics regardless of affiliations within the holding company structure. For example, the British Columbia Utilities Commission (the "BCUC") reiterated its adherence to this principle in its most recent generic cost of capital decision:

> *In the BCUC's application of the Fair Return Standard, the utility must also be assessed based on the standalone principle. That principle provides that the utility should be regulated as if it were a standalone entity, raising capital on the merits of its own business and financial characteristics, regardless of affiliations within the holding company structure. The BCUC had noted the relevance of the standalone principle in past cost of capital decisions, and we continue to adhere to this principle to determine FEI and FBC's cost of capital in this proceeding.*[21]

The OEB has also 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,"[22] and that "Provincial ownership will not be a factor to be considered by the Board in establishing capital structure."[23]

In Concentric's view, it is consistent with both financial theory and regulatory practice to determine the cost of capital based on the *use* of funds and not the *source* of funds when determining just and reasonable rates. The OEB found the same 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."[24] This principle is consistent with the application of the stand-alone principle.

C. Relationship Between Capital Structure and ROE

The deemed equity ratio and authorized ROE must be considered together to determine whether the Fair Return Standard has been met. Other factors being equal, firms with lower common equity ratios

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21 British Columbia Utilities Commission, Generic Cost of Capital Proceeding (Stage 1) Decision and Order G-236-23, September 5, 2023, p. i-ii.
22 EB-2007-0905, Decision with Reasons, November 3, 2008, p. 140.
23 *Id*., at 142.
24 EB-2024-0063, Decision and Order, March 27, 2025, at 18.

require higher rates of return to compensate for the additional financial risks faced by their shareholders. Consequently, when a regulator approves a deemed capital structure, that decision impacts the required rate of return on equity. As fixed debt obligations increase, the equity buffer (unencumbered earnings available to shareholders) narrows, and the required equity return increases to compensate investors for the additional risk to earnings. The fair return, therefore, depends on both the equity return and capital structure. The exact tradeoffs between the ROE and equity ratio are difficult to quantify with precision, but widely used leverage models such as the Hamada equation (which is an extension of the Modigliani-Miller theorem on capital structure) are based on the fundamental premise that there is a link between the cost of equity and the capital structure – as the capital structure becomes more leveraged, the cost of equity increases.

North American regulatory practice generally follows two alternative approaches to setting the capital structure and ROE: 1) the generic approach, and 2) setting ROE and capital structure based on individual proceedings. In Canada, the generic approach is common practice, but this approach is applied differently across provinces. Some jurisdictions use a single authorized ROE applicable to the generic or benchmark utility and reflect differentiation in utility risk through a deemed equity ratio (e.g., historically Ontario[25] and Alberta[26]). Other jurisdictions provide a generic ROE and differentiate the utility risk profile through an adjustment to the utility's ROE, or its deemed capital structure, or both (e.g., British Columbia[27] and Quebec[28]). In the U.S., the utility's actual book capital structure is often an important factor for ratemaking purposes, and regulators most often determine the reasonableness of each utility's capital structure based on that utility's risk profile relative to its proxy group, peer equity ratios, credit metrics, and specific circumstances. Capital structure is most often assessed each time the ROE is established, typically in individual utility rate proceedings.

Investors also consider the business and financial risks of a particular company relative to other similarly situated companies in the same industry. For example, as mentioned previously, the OEB has expressed its view that "the capital attraction standard, indeed the [Fair Return Standard] in totality, will be met if the cost of capital determined by the Board is sufficient to attract capital on a

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25 Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, EB-2009-0084 (December 11, 2009), at 50.

26 Alberta Utilities Commission, 2013 Generic Cost of Capital Decision, Decision 2191-D01-2015 (March 23, 2015) para. 416, at 84.

27 British Columbia Utilities Commission, Generic Cost of Capital Proceeding (Stage 2) Decision (March 25, 2014).

28 The Régie has awarded different capital structures and returns on equity for Gazifére (9.05% on 40% equity, D-2022-119, R-4156-2021 Phase 2, October 26, 2022), Gaz Métro (8.9% on 38.5% equity, Decision D-2022-119, R-4156-2021, Phase 2, October 26, 2022), and Hydro Québec Distribution (8.2% on 35% and Hydro Quebec TransÉnergie at 8.2% on 30%, D-2014-037, R-3854-2013, Phase 1, March 6, 2014).

long-term sustainable basis given the opportunity costs of capital."[29] The "opportunity cost of capital" is the return available in investments of similar risk. Further, the OEB has determined that "[t]he comparable investment standard requires empirical analysis to determine the similarities and differences between rate-regulated utilities." However, the assessment of comparability "does not require that those entities be 'the same'."[30]

[29] Ontario Energy Board, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, EB-2009-0084 (December 11, 2009), at 20.
[30] *Id.*, at 21.

SECTION 4:
COMPANY-FOCUSED ASSESSMENT: CHANGES IN BUSINESS AND FINANCIAL RISKS

A. Method for Assessing Business and Financial Risk

The cost of capital is a forward-looking concept, and utility investors tend to be long-term providers of capital. For these reasons, it is important to not only review OPG's current business and financial risk profile, but also to assess how that risk profile has changed and will change going forward. This approach is consistent with the OEB's findings in prior decisions regarding OPG's capital structure.[31] Specifically, the Board has determined in prior decisions that a utility must demonstrate that there has been a material change in its business or financial risk in order for the Board to consider whether a change in the utility's deemed equity ratio is warranted.

Business risk for a regulated utility results from variability in cash flows and earnings, historically or prospectively, that impact the ability of the utility to recover its costs including a fair return on, and of, its capital in a timely manner. Concentric includes operating risk and regulatory risk under this broad definition of business risk. Financial risk relates to a company's debt leverage and liquidity and is reflected in its credit profile. Both business and financial risk have a direct bearing on a utility's cost of capital.

For generators and vertically-integrated utilities, a key risk determinant is the type of generation assets the utilities own, as well as the mix and diversity of those assets. In addition, Concentric typically considers the following factors in evaluating the business and financial risk of regulated utilities: (1) the magnitude of the utility's projected capital expenditure program and how that compares to other peer group companies; (2) the regulatory environment in which the utility provides services; (3) industry trends, including how the energy landscape and demand are evolving and environmental factors such as how severe weather is affecting the utility's business plan; (4) the operational risk profile of the utility, including any factors that are unique to the utility relative to industry peers; and (5) the utility's financial risk profile, including its capital structure, credit rating, and credit outlook.

[31] For example, in EB-2013-0321, the Board determined that because the business risk for OPG's regulated operations had changed in the specific payment-setting period in that proceeding, the capital structure should reflect that change. In EB-2024-0063 (EB-2024-0063, Decision and Order, March 27, 2025, at 55), the OEB agreed that OPG could submit evidence in its next payment amounts application on proposed changes to its deemed capital structure as a result of material changes in OPG's business and financial risk profile.

To evaluate OPG's business and financial risks, Concentric performed an independent review of the Company, building on our previous reports and analysis in EB-2016-0152 and EB-2020-0290. The review included:

(1) Trends in electricity demand that are driving the need for OPG's capital investments;
(2) The business mix between regulated hydroelectric and nuclear generation, and how that mix has changed and is expected to continue to change over the rate-setting period;
(3) Key risks related to OPG's prescribed nuclear facilities, including the PRP nuclear operating risks;
(4) Risk factors associated with OPG's prescribed hydroelectric facilities, including the current and upcoming major turbine-generator refurbishment or redevelopment of those units;
(5) The impact of other external factors such as severe weather conditions and cybersecurity risk;
(6) An assessment of the regulatory environment in Ontario and how that affects OPG's risk profile; and
(7) A review of the key factors affecting OPG's financial risk.

B. Increasing Demand for Electricity

Higher capital spending on energy projects in Ontario is being driven by an increased focus on the security and reliability of energy sources and an anticipated increased demand for electricity. The trend in electricity usage is not specific to Ontario or even Canada, as the International Energy Agency, describing the arrival of the "age of electricity," forecasts worldwide electricity usage to grow by 40% by 2035 compared to 2024,[32] a rate of 3.1% per year. In Ontario, the Ontario Independent Electricity System Operator ("IESO") forecasts that electricity demand in the province is expected to increase by 65% from 2026 to 2050.[33] This is illustrated in Figure 2 below. To meet the projected demand, Ontario expects to need additional generating capacity estimated at 16,000 MW by 2050, in addition to new transmission infrastructure.[34] The required investments must be matched with appropriate financial incentives to prevent a gap between supply and demand.

32 S&P Global, "IEA sees global power demand rise 40% by 2035 as 'age of electricity' arrives," November 12, 2025.
33 IESO, 2026 Annual Planning Outlook: 2026 Demand Forecasts, November 18, 2025, at 8.
34 Province of Ontario, News Release, "Ontario Generating More Energy to Meet Soaring Demand," November 27, 2024.

In June 2025, Ontario released "Energy for Generations," Ontario's first Integrated Energy Plan that is founded on other recent work by the Province related to actions needed to meet growing electricity demand, electrification and energy transition, and affordable energy.[35] It also discusses the drivers of growing demand for electricity, including economic growth, population growth, and electrification.[36] The Integrated Energy Plan discusses the strategies Ontario is taking to meet this forecasted increase in electricity demand, including:

> *[R]efurbishing and expanding Ontario's nuclear fleet, renewing aging hydroelectric stations, launching competitive procurements for new generation and storage, and advancing the predevelopment of major projects like pumped storage, which will ensure [Ontario will] have a secure, reliable and clean system in the years ahead while reducing long-term system costs.*[37]

With specific regard to the types of projects OPG is undergoing, the Integrated Energy Plan notes that "refurbishments are essential to extending the life of Ontario's nuclear units and securing decades of reliable, zero-emissions electricity. Once complete, the province will benefit from renewed baseload capacity while reducing natural gas usage on the grid,"[38] and "[u]nder *Energy for Generations*, clean, affordable and reliable nuclear power will continue to serve as the backbone of the province's electricity system providing the 24/7 baseload power the province's economy requires."[39]

The investment community has taken notice as well. For example, investment bank RBC has previously estimated that up to $450 billion of capital investment will be needed in energy-related projects in Ontario by 2050, with a significant amount for generation resources to reduce carbon emissions and meet rising demand for electricity due to electrification of buildings, installation of heat pumps, and electric vehicle adoption.[40]

As shown in Figure 2 below, the IESO has estimated that total net annual energy demand in Ontario is projected to increase from just over 150 TWh in 2026 to 250 TWh by 2050 in its reference scenario (dark blue line), a 65% increase or a 2.1% compound annual growth rate.

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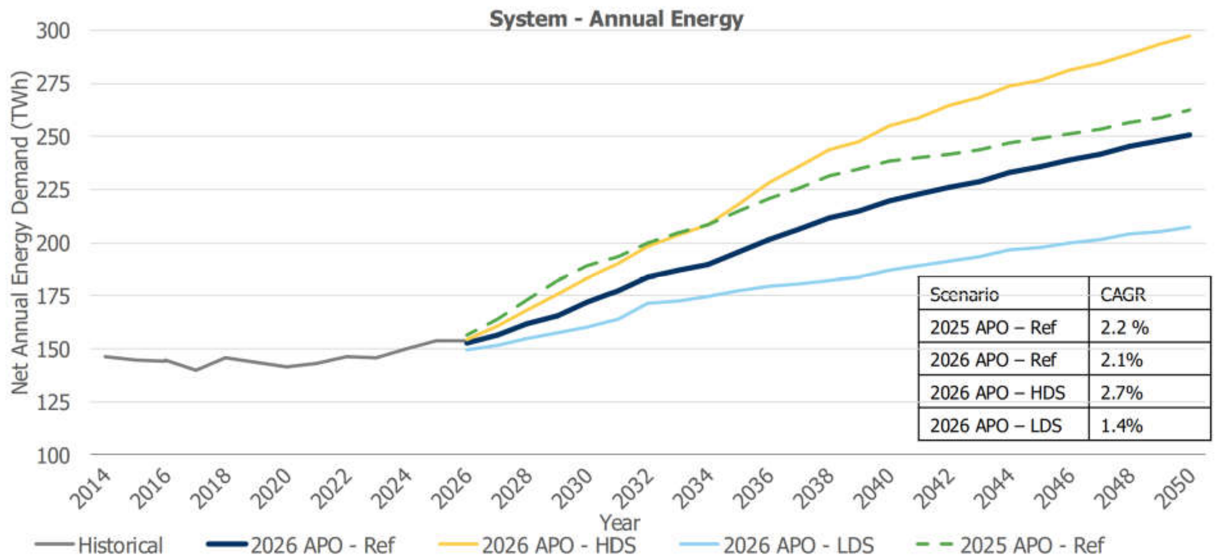
35 Province of Ontario, "Energy for Generations," June 2025, at 9.
36 *Id.,* at 20.
37 *Id.,* at 40.
38 *Id.,* at 41.
39 *Id.,* at 42.
40 RBC Climate Action Institute, "Power Shift: How Ontario Can Cut its $450-billion Electricity Bill," June 18, 2023, at 1-2.

Figure 2: Ontario Annual Energy Demand Forecast[41]



While the energy outlook and system capacity projections are likely to continue to be refined over time, the current overall trajectory of the demand for electricity in Ontario and associated government policy underscore the need for OPG to invest significantly in the refurbishment and reliability of its assets. Many of these projects typically involve longer development and construction cycles and must be carefully planned and executed to ensure the assets are available to meet a range of potential future energy demand outcomes.

C. OPG's Shifting Nuclear-Hydroelectric Mix

As described below, OPG is investing significantly in its generation facilities, with the largest projects over the last decade and through the IR Term being the DRP and the PRP. Because of the magnitude of those projects, OPG's rate base has shifted from being majority hydroelectric to majority nuclear and will continue shifting further towards nuclear through 2031. Concentric considered the evolution of the relative mix between OPG's regulated nuclear and regulated hydroelectric operations since EB-2016-0152 and since EB-2020-0290 and the change in that mix over time as a determinant of risk. The OEB has previously found nuclear generation to be riskier than hydroelectric generation,[42] and that finding is supported by DBRS, for example, which states:

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41 IESO, 2026 Annual Planning Outlook: 2026 Demand Forecasts, November 18, 2025, at 8.

42 For example, in EB-2013-0321, the OEB found that "[t]he relative business risk of hydroelectric generation versus nuclear has been accepted by the Board as being lower in previous proceedings, even though setting the capital structure on a technology specific basis has not." *See*, EB-2013-0321, November 20, 2014, Decision with Reasons, at 113.

> *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.*[43]

In addition, Appendix B provides excerpts from S&P highlighting the ratings agency's views on the high-risk nature of utilities' nuclear businesses.

The OEB has previously evaluated this nuclear/hydroelectric split in two different ways, based on the proportionate share of rate base amounts (i.e., asset-based considerations)[44] and based on the ratio of generation output (i.e., revenue-based considerations).[45] From an investment risk perspective, the primary basis on which to assess the relative business risk of OPG's regulated business segments, particularly during a construction cycle, is on invested capital and the earnings that it generates. This is because it is investment in plant – ultimately recovered over output through the payment amounts – that drives the need for capital, generates earnings, and is the critical determinant of risk, notwithstanding changes in relative generation output. To apply this in OPG's context, it would be improbable that investors would reduce or keep a neutral risk view of OPG if OPG were seeking investment to support a nuclear capital program because of a temporary reduction in the nuclear generation output reflecting, in large part, that very capital program. Likewise, once the PRP is completed and both Darlington and Pickering facilities are fully back in operation, OPG's nuclear output will increase, yet at that point, assuming successful completion of the PRP, one of today's key risk factors will be behind the Company.

Rate base reflects the amount of capital investors have at risk and the investment base upon which a utility has the opportunity to earn a rate of return. By way of example, if a generation plant were to hypothetically generate $0 in revenue in one year due to unexpectedly not producing any electricity, that would negatively impact the return to investors in that year (all else equal), albeit potentially on a transitory basis, due to non-recovery of a portion of capital (and operating) costs. If, however, some or all of the capital costs of that same plant are written off as not recoverable, that would clearly have a more significant and lasting negative impact on the investment and its earnings potential. By way

43 DBRS Morningstar, "Ontario Power Generation Inc.," April 21, 2025, at 3.

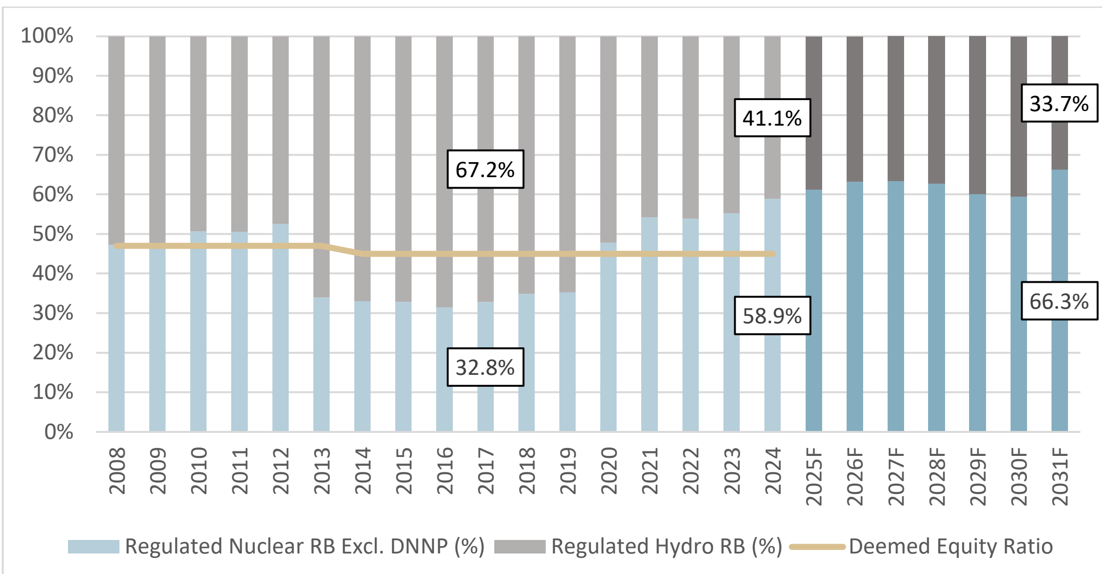
44 OEB Decision EB-2013-0321, November 20, 2014, Decision with Reasons, at 114, where the OEB found that "[t]he business risk is reduced because of the addition of significant hydroelectric assets to rate base, which are less risky than nuclear assets."

45 OEB Decision EB-2016-0152, December 28, 2017, Decision and Order, at 102, where the OEB found that "[t]he relative contributions of revenue from hydroelectric and nuclear will not change in favour of nuclear, so it is not axiomatic that the equity thickness should be increased on this basis."

of another example, if one utility were to make a significant investment in a lower capacity factor facility (e.g., to meet periods of high demand) and another utility were to make a smaller investment in a higher capacity factor facility (e.g., to meet baseload demand), attributing higher operating risk to the less expensive but higher producing facility would significantly understate the associated risk.

As shown in Figure 3 below, the nuclear portion of OPG's regulated generation rate base has increased steadily since 2017, the first year in the rate plan established in EB-2016-0152. Nuclear rate base is projected to increase from 32.8% in 2017 to 66.3% in 2031, while hydroelectric rate base is projected to decline from 67.2% in 2017 to 33.7% in 2031. This represents a clear and material shift in OPG's asset base to nuclear generation plant, which is significantly riskier than hydroelectric generation.

Figure 3: Nuclear/Hydro Split by Rate Base



Concentric also considered how the relative decline in OPG's nuclear generation affects risk and concludes that OPG also faces higher generation output risk. Specifically, due to the decline in nuclear generation in absolute terms and relative to hydroelectric generation, OPG is exposed to increased cost recovery risk, particularly as nuclear rate base simultaneously increases. OPG forecasts to produce just 126 TWh from nuclear sources in the 2027-2031 rate period, a 28% decrease from the 2022-2026 total of 175 TWh and a more than 39% decrease from the 2017-2021 historical total of 209 TWh.

As nuclear generation declines, each unit of this output must recover a greater unit of OPG's nuclear revenue requirement, which means that any potential outage at a nuclear plant not factored into the setting of the payment amounts will cost OPG much more on a per-MWh basis than it would have five or ten years ago. Furthermore, this increase in how much each nuclear MWh is worth to OPG is greater than the increase in how much each hydroelectric MWh is worth, meaning that a potential outage at a nuclear plant of a given duration will cause OPG a greater loss relative to a similar length outage at a hydroelectric facility than it did in the past. OPG's unique exposure to a 100% variable rate for nuclear production further underscores the increased generation output risk, including relative to hydroelectric operations, which have some regulatory protections in place around output variability (e.g., changes in water flow levels).

The increasing value of each unit of nuclear output (on an absolute basis and in relation to each unit of hydroelectric output), is demonstrated in Figure 4 below.

Figure 4: Value of Nuclear and Hydroelectric Output

	Value of a TWh of Output ($millions)	
	Nuclear	Hydroelectric
EB-2016-0152 Rate Term	$82	$43
EB-2020-0290 Rate Term	$106	$44
2027-2029	$201	$55

As shown in Figure 4 above, each nuclear TWh had a value of approximately $82 million during the EB-2016-0152 rate term, compared to approximately $43 million for a hydroelectric TWh.[46] During the EB-2020-0290 rate term, the value of a nuclear TWh increased to approximately $106 million, compared to approximately $44 million for a hydroelectric TWh.[47] Over 2027 to 2029,[48] based on OPG's draft rate filing at the time of writing, the proposed value of a nuclear TWh will increase to approximately $201 million, compared to approximately $55 million for a hydroelectric TWh, or approximately 146% higher than in EB-2016-0152 and 90% higher than in EB-2020-0290.

This represents an approximately 273% increase in the amount by which the nuclear unit of output is more valuable than the hydroelectric unit of output since EB-2016-0152, and an approximately

46 For nuclear, based on EB-2016-0152 approved smoothed base payment amounts, arithmetically averaged over 2017 to 2021. For hydroelectric, based on approved base payment amounts pursuant to the IRM formula in EB-2016-0152 and subsequent annual proceedings, arithmetically averaged over 2017 to 2021.

47 For nuclear, based on EB-2020-0290 approved smoothed base payment amounts, arithmetically averaged over 2022 to 2026. For hydroelectric, based on the approved 2021 base payment amount that was held constant over the period pursuant to O. Reg. 53/05.

48 OPG's draft rate filing rates have been calculated inclusive of DNNP, for which the first unit is anticipated to enter service in 2030. To minimize the impact of the DNNP on the nuclear rates for OPG's existing facilities, the period of 2027-2029 draft rates has been used for this analysis.

135% increase in the amount by which the nuclear unit of output is more valuable than the hydroelectric unit of output since EB-2020-0290.

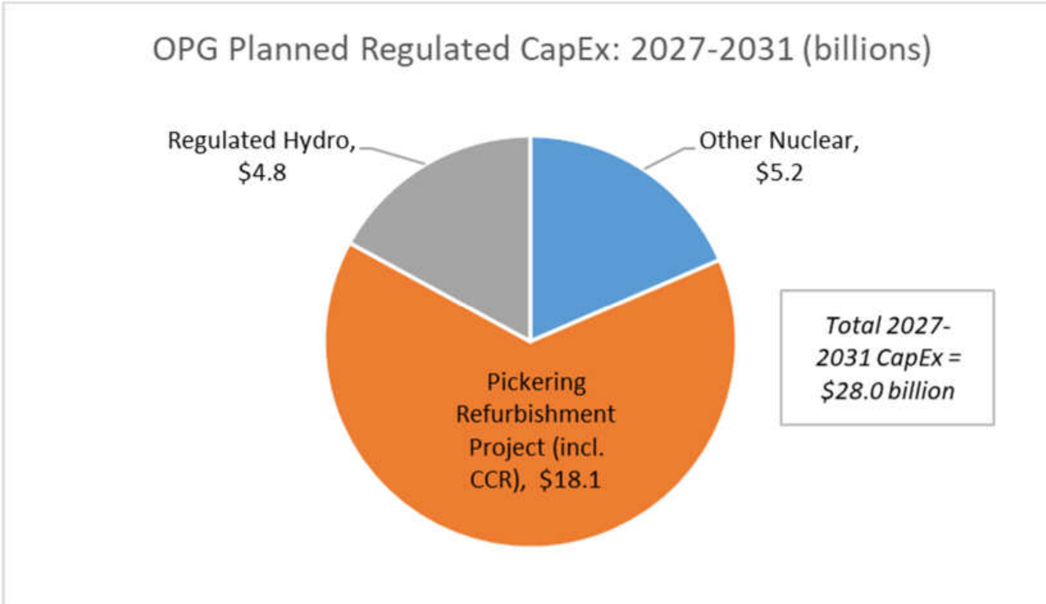
To put the above figures into further perspective, foregone revenues from a hypothetical seven-day outage at one of OPG's Darlington nuclear reactors would have been approximately $12 million during the EB-2016-0152 period, increasing to $15 million in EB-2020-0290, and nearly $29 million in the upcoming IR Term. Contextually, an outage at one of OPG's Darlington reactors during most of the upcoming IR Term would result in a loss of a quarter of OPG's nuclear generating capacity.

These combined factors indicate that OPG's nuclear-specific risks will be at the forefront in the upcoming rate period, resulting in greater overall risk for the Company.

C. OPG's Elevated Capital Spending Program

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. This is also the cause of the continued shift to a greater proportion of investment in nuclear generation versus hydroelectric generation that began a decade ago. OPG's elevated CapEx program places pressure on the Company's cash flows and highlights the importance of a strong balance sheet and sufficient revenues to cover the Company's costs, including the cost of capital. As shown in Figure 5 below, the Company projects capital spending of approximately $28.0 billion over the rate period, excluding DNNP. This represents 142% of 2024 year-end regulated rate base of $19.7 billion, a proportion that has increased since the 2017-2021 rate period, when capital spending of $8.1 billion represented just 75% of 2016 rate base.

Figure 5: OPG's Projected Capital Expenditures on Major Programs and Projects



1. Overview of Major Capital Projects

Figure 6 below provides a brief overview of OPG's major capital programs for the prescribed assets during the 2027-2031 rate period. In addition to the PRP, OPG continues to execute ongoing capital projects to maintain reliability and safety across its generating assets, including investments to address emergent reliability risks at Darlington for equipment that did not form part of the DRP scope as well as those necessary to extend the operating life and sustain performance for an aging hydroelectric fleet.

Figure 6: Highlights of OPG's Major Capital Projects

Project	Description
Pickering Refurbishment Program	After initially shutting down in 2026, Units 5–8 will be refurbished over the 2027-2034 period at an estimated cost of $26.8 billion ($18.1 billion over 2027-2031).
Hydroelectric Refurbishment and Redevelopment Projects	OPG will refurbish or redevelop a number of aging hydroelectric stations across its fleet of 54 facilities at an estimated cost of $2.4 billion from 2027-2031.
Darlington Turbine Rotors Replacement Project	Following the detection of stress corrosion cracking in the Darlington rotors set, this project will replace the high and low-pressure turbines in Darlington Units 1-4 (and purchases capital spares) at an estimated cost of $2.3 billion ($1.7 billion over 2027-2031).

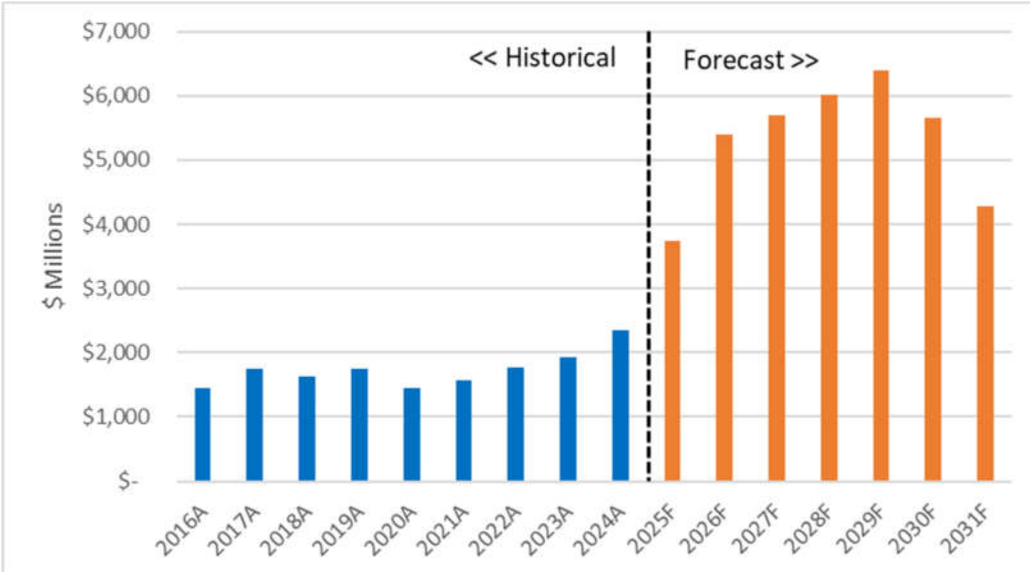
As described in greater detail below, the capital outlays for the upcoming rate term are significantly higher than previously experienced. Additionally, the project specific risks related to the PRP are higher than those related to the DRP, which will also be further discussed below.

It is worth noting that OPG is undertaking this significantly expanded capital program at the same time as the global supply chain is under pressure from competing energy infrastructure projects and geopolitical constraints associated with the global trade environment. These factors can disrupt the availability and/or increase the cost of materials and equipment, contributing to elevated risks of project delays and cost escalation. Global and domestic competition for skilled labor is another prevailing risk in the current environment, as further discussed with reference to the PRP below.

2. Comparison to Historical Levels and to Peer Group

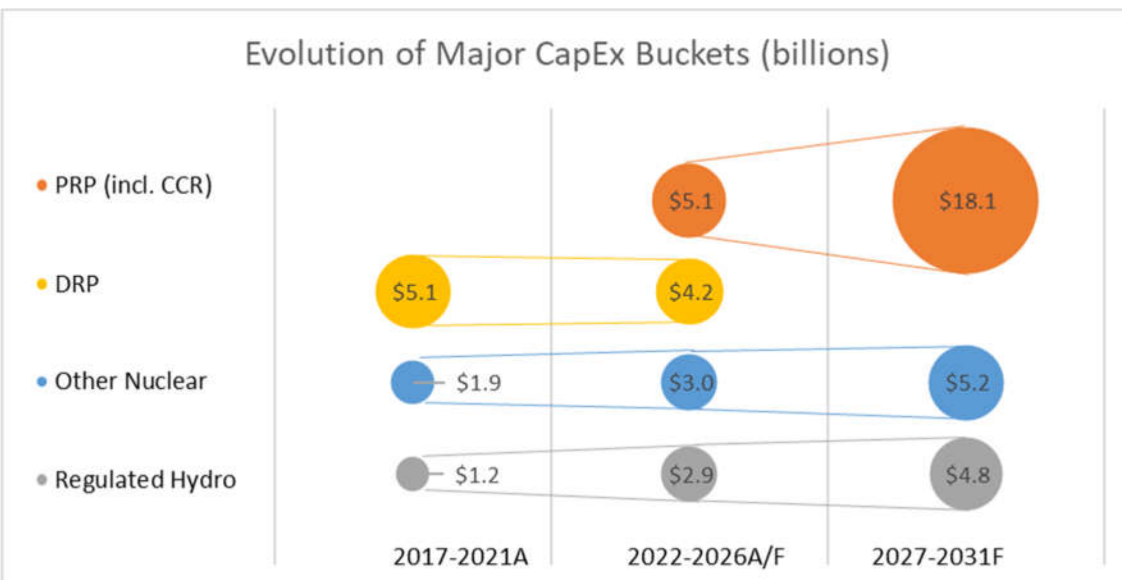
To put the magnitude of OPG's capital spending program in context, Concentric compared OPG's projected capital expenditures for its regulated segment (excluding DNNP) to actual historical spending since 2016. As shown in Figure 7, OPG is projected to spend significantly more in CapEx than it has in prior years, largely driven by the PRP and hydroelectric refurbishment and redevelopment projects. OPG's 2027-2031 capital expenditures are forecast to total $28.0 billion, more than 1.8 times as large as the currently forecasted 2022-2026 total of $15.2 billion and more than 3.4 times as large as the 2017-2021 total of $8.1 billion.

Figure 7: OPG's Projected Regulated Segment CapEx



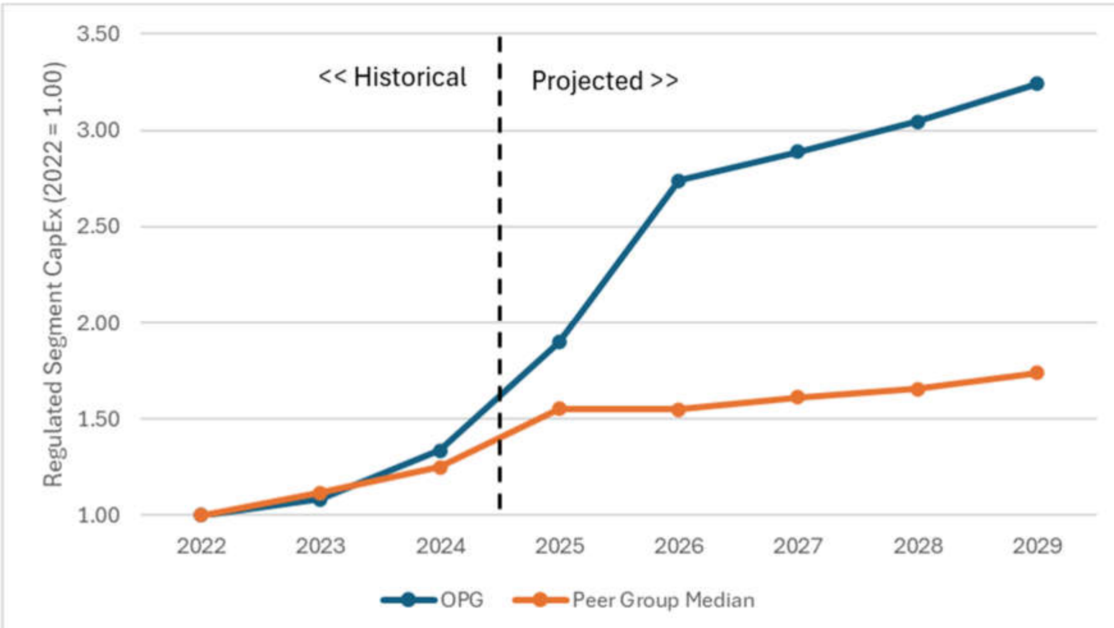
The largest driver of the CapEx increase is the PRP, with incremental increases in other nuclear and regulated hydroelectric as well. An illustration of the growth of OPG's major capital spending programs over the prior two rate periods is provided in Figure 8, below.

Figure 8: Evolution of Major CapEx Categories (billions)



Concentric also benchmarked OPG's capital spending growth against historical and stated capital plans of the peer group companies. Specifically, Concentric compared historical CapEx in 2022 versus projected CapEx in the period 2025-2029.[49] As shown in Figure 9 below, OPG's regulated segment CapEx (excluding DNNP) is projected to grow at a much greater rate than peer companies' CapEx, reaching over 2.7 times 2022 levels by 2026. In comparison, the peer group median in 2026 is only 1.5 times the 2022 levels, indicating that, on a growth basis alone, OPG will experience greater than average risk relative to its peers.

Figure 9: Historical vs. Projected CapEx – OPG vs. the Main Peer Group



In addition, on a relative basis when compared to net plant, OPG's capital spending program comprises a larger portion of its net plant versus other companies in the peer group. OPG's CapEx in 2025-2029 represents 106% of its 2024 regulated net plant, whereas the median ratio for the peer group is just 68%. Adding plant to a relatively smaller asset base indicates that OPG will experience greater risk than will companies in the peer group. Finally, beyond the size of its capital program, the nature of OPG's CapEx investments and the heavy focus on nuclear refurbishments, set OPG apart from peers in terms of the complexity of its construction plan.

3. Assessment of Business and Operating Risk

In addition to our evaluation of the relative mix of OPG's nuclear and hydroelectric rate bases and the scale of OPG's capital program, Concentric performed an assessment of business and operating risks

49 Please see Section 6 for further details regarding the peer group. For peer companies, stated 2025-2029 capital plans were drawn from Form 10-Ks and annual reports.

for OPG. This section summarizes the key findings of that risk assessment and identifies several important business and operating risks that are not fully mitigated through economic regulation.

a. Pickering Refurbishment

In 2022, the Province of Ontario requested OPG to assess the feasibility of refurbishing Pickering Units 5-8, and OPG completed its updated assessment in 2023, with the Province of Ontario subsequently announcing its support for steps to be taken toward the potential project in January 2024 and subsequently in January 2025. Ontario approved OPG's plan for the PRP on November 26, 2025.[50] The PRP is a multi-year, $26.8 billion project to refurbish Units 5-8 at Pickering. The refurbishment will entail the "retubing" of each reactor (i.e., the removal and replacement of the fuel channels, calandria tubes, and feeders and feeder cabinets), the replacement of the steam generators, refurbishment of high pressure and low pressure turbine generators, the construction of a new deep water intake structure, and 124 other projects across the four units.[51] The first unit is scheduled to be returned to service in 2031 and the full project completed by 2034.

OPG is embarking on the PRP at an estimated cost of $26.8 billion. Pickering Units 5-8 are planned to be taken offline in September 2026 before transitioning to refurbishment beginning in 2027. At the time of the prior rates application in 2020, OPG was planning to shut down all the units at Pickering. While OPG has demonstrated, through the DRP, its ability to manage a large nuclear refurbishment within scheduled timelines and budgets, the PRP will proceed with material differences in scope and schedule, which add complexity and risk to the execution of the project. Beyond inherent "mega project" risks of the PRP, the other key risks include the age of the plant, differences in the scope of work between the PRP and the DRP, added schedule risks, site location, and regulatory risks. Descriptions of these factors are provided below.

- *Age of Facility:* Pickering Units 5-8 were commissioned between 1983 and 1986 and are almost a decade older than Darlington Units 1-4, which were commissioned between 1989 and 1992. This leads to more components needing replacement or refurbishment to address equipment reliability and obsolescence issues, ensure compliance with current codes and standards, and modernize technology to support extended operations. Additionally, given their end-of-life condition, all four Pickering units must be laid up during the refurbishment, which can increase the complexities with return to service due to the extended time between

50 Ontario Ministry of Energy and Mines press release, "Ontario Greenlights Pickering Nuclear Generating Station Refurbishment to Create Nearly 37,000 Jobs," November 26, 2025.
51 Ontario Power Generation Inc., "Pickering Refurbishment Project," June 2025.

the units coming offline and being commissioned. Significantly, Pickering will require replacement of the digital control computer equipment, which was not required at Darlington.

- *Major Scope Differences:* There are certain important differences in the scope of work for the PRP compared to the DRP, which add complexity to the PRP. Some of the key differences are described below.
    - *Steam Generator Replacement:* Pickering will require 48 steam generators to be replaced in contrast to Darlington, which did not require any steam generator replacements. This will involve complete removal and installation of new steam generators, necessitating the creation of two access points in the roof of each reactor unit containment dome to facilitate removal and installation of the steam generators. Pickering will also need to create suitable storage and travel routes required for the handling and storage of the 48 steam generators, both the old and the new.
    - *Turbine Generator:* The PRP will be undertaking a significantly larger scope of work associated with the turbine generators than was undertaken in the DRP, including full replacement of the low pressure turbine rotors, high pressure turbine rotor replacements in most units, a full program of generator stator and rotor rewind (where only partial rewind was performed at Darlington), and generator core replacement.
    - *Deep Water Intake:* The PRP is undertaking a full replacement of the existing surface level water intake system with a new deep water intake mechanism. This is a significant project estimated to cost $1.4 billion, and involves excavation, tunneling, and installation of new intake structures, forebay and intake system modifications, power and infrastructure development, and the construction of a cut-off wall. This project carries geotechnical and subsurface condition risks, as well as uncertainty associated with underground tunneling.
- *Schedule Risks:* In addition to the compressed planning timeline, the PRP has a heavily overlapped schedule for the unit refurbishments. This is in contrast with the DRP which, following an extended planning phase, proceeded to complete the refurbishment of the first unit before moving forward with the subsequent units, with no more than two units in refurbishment at any one time. These schedule factors translate into added risk factors to meeting the PRP's cost and schedule commitments. For example, significantly overlapped

execution can increase the complexity of work sequencing, and create logistical challenges due to a higher peak on-site staffing presence.

- *Skilled Labor:* The risk associated with obtaining skilled labor is elevated in the current environment because many North American electric utilities have announced, or are considering, plans to build or refurbish generation facilities in response to increasing demand due to, among others, the electrification of buildings and construction of data centers in their service territories. Canada's energy sector faces a structurally tight labor market. According to the Electricity Human Resources Canada, the industry will require nearly 28,000 new workers by 2028 in a "path to net-zero" scenario, with 57% to replace retirees and 43% to support growth.[52] While the PRP will be able to rely, to a greater degree than the DRP, on its existing station workforce to perform certain activities within the PRP due to all Pickering units being offline for a portion of the project, it is exposed to heightened skilled labor availability risk in areas where resources must be externally sourced.
- *Site Location:* Relative to Toronto, Pickering is located much closer than Darlington, which can present additional logistical challenges in access and egress to/from the site around traffic congestion and municipal road and infrastructure construction.
- *Regulatory*: The PRP has pending regulatory approvals from the Canadian Nuclear Safety Commission, with the potential that they are approved in parallel to the first unit execution, creating risks related to required regulatory changes or delays.

b. Nuclear Operations

As an owner and operator of two nuclear plants, OPG faces unique risks including equipment risks and the risk of planned and unplanned outages due to emergent issues. The upcoming turbine rotors replacement project at Darlington is an example of how emergent issues can have significant impacts on outage planning and capital costs. OPG also has other large emergent equipment replacement or rehabilitation projects scheduled at Darlington in the IR Term, representing risks that must be managed to ensure reliable post-refurbishment station performance. The emergence of these equipment issues highlights OPG's heightened risk exposure to nuclear generation loss at a time when it will only have one nuclear station producing electricity.

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52 Electricity Human Resources Canada, "Electricity in Demand: Labour Market Insights 2023-2028 (https://ehrc.ca/labour-market-intelligence/electricity-in-demand-labour-market-insights-2023-2028/).

As a result of these and other nuclear operation risks, OPG is exposed to fluctuations in cash flows and cost recovery. Nuclear operators also face regulatory risks associated with nuclear operations, the need for periodic license renewals, major industry events that can affect investor and public perception of nuclear facilities, and the need for regulatory and environmental approvals.

As detailed in Appendix B, investors consider nuclear operations as a source of increased risk for regulated utilities, including that: "[n]uclear generation increases operational risks and carries long-term storage concerns,"[53] and that "exposure to nuclear generation introduces higher operational risks and plant retirement responsibilities."[54]

c. Hydroelectric Refurbishment

OPG's regulated hydroelectric fleet has an average age of over 90 years. To extend the life of aging assets and address safety and reliability risks, OPG is entering a stage of major refurbishment and other sustaining capital work across its 54 hydroelectric plants at an estimated cost of $6.6 billion from 2025-2031. 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.

Significant aging risks for the hydroelectric assets include degradation and deterioration of structures due to environmental factors (e.g., thermal expansion and contraction, freeze-thaw damage, and corrosion). For example, several of OPG's regulated hydroelectric stations, including the R.H. Saunders station that is the second largest in OPG's regulated hydroelectric fleet, are subject to a chemical reaction that leads to concrete degradation, the determination of the severity of which may require invasive procedures. To address these and other risks, necessary concrete repair and rehabilitation at OPG's regulated hydroelectric assets is forecast to increase over the business plan period.

4. Environmental and Severe Weather Risks

Environmental and severe weather risks are impacting utilities globally, resulting in more frequent

53 S&P Ratings Direct, "Ameren Corp.", April 16, 2025.
54 S&P Ratings Direct, "American Electric Power Co. Inc.", September 19, 2023.

storm damage and weather-related outages, and increased spending on preparing assets to withstand physical risks. In fact, S&P identifies that "[u]tilities face the highest combined physical risk from climate hazards like water stress, storms and wildfires among different industries."[55] These risks, which have intensified since 2020 and are anticipated to continue to do so over the IR Term, also relate to the need for resiliency planning and costs.

For example, in 2022, OPG experienced a historic flooding event along the English and Winnipeg rivers that resulted in damage to hydroelectric generating stations requiring additional costs for capital upgrades and maintenance to repair damage.[56] In addition, wildfires have become more prevalent, with the Globe and Mail reporting the following:

> *Canada's wildfire seasons have changed. It's apparent in the earlier starts and later finishes, fires threatening communities from early spring through to the fall. More than 30,000 people were displaced by wildfires in Saskatchewan and Manitoba alone this year, before even the start of summer. It's apparent also in the catastrophic damage fires now leave behind. In 2023, the country's most destructive wildfire season to date, more than 173,400 square kilometres burned – more than double the previous record and six times more than the 10-year average.*[57]

Specific to the Company, in May 2025 OPG's Caribou and Whitedog stations were impacted by wildfires for nearly three weeks, resulting in lost production due to emergency directives preventing operators from accessing the stations.[58]

Resilience and preparedness requirements also create additional risks and costs for utilities. For example, in 2023, Ontario's Minister of Energy at the time recognized the value of climate change resiliency in a mandate letter to the OEB related to distribution utilities,[59] directing the OEB to implement policies around storm recovery, climate resilience in asset and investment planning and vulnerability assessments. Additionally, as per the North American Electric Reliability Corporation's ("NERC's") 2025 State of Reliability, Assessment Overview of 2025 Bulk Power System Performance, severe weather, including winter storms, remained responsible for the most severe outages in

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55 https://www.spglobal.com/market-intelligence/en/news-insights/articles/2021/9/utilities-face-greatest-threat-as-climate-risks-intensify-66613890.
56 CBC News, "Flooding in northwestern Ontario likely to get worse before it gets better, officials say," May 19, 2022.
57 The Globe and Mail, "How can Canada fight fires, better?" August 27, 2025.
58 CBC News, "Evacuation order remains in effect as Kenora 20 still 'significant fire of concern' for northwestern Ontario", May 14, 2025.
59 https://oeb.ca/sites/default/files/letter-of-direction-from-the-Minister-of-Energy-20231129.pdf.

2024.[60] Severe weather is increasingly leading to regulatory directives and additional reliability standards for utilities.[61]

5. Cyber Security

OPG faces an escalating cybersecurity threat due to a widening range of tactics being used to attack both information technology and operational technology systems. As noted in the Canadian Centre for Cyber Security's 2025-2026 National Cyber Threat Assessment ("NCTA"), "[i]n the last two years, we [Canada] have witnessed a sharp increase in both the number and severity of cyber incidents, many of which target our essential services."[62] The NCTA identifies that, from 2022 to 2023, ransomware incidents attacking energy companies increased by 67%, citing as an example the 2021 ransomware incident on the Colonial Pipeline in the U.S.[63] A more recent example of a cybersecurity attack on an electric utility is that of Nova Scotia Power, which announced it was responding to a cybersecurity incident on April 28, 2025[64] that was later confirmed to have exposed private customer information.[65]

To combat increasing cybersecurity threats, compliance demands are increasing, for instance with revisions to nuclear-specific cybersecurity requirements.[66] In addition, the NERC has identified cyber and physical security complexity as one of six "risk themes" in 2025, noting that "[t]he growing complexity of system equipment and operations increases security challenges and enhances the attractiveness of the grid as a target,"[67] grouping its recommendations into themes including more comprehensive studies and assessments and more preparation.[68] In Ontario, since 2020, there have been 14 new or revised NERC Critical Infrastructure Protection ("CIP") standards applicable to OPG

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60 NERC, "2025 State of Reliability," June 2025.

61 For example, the U.S. Federal Energy Regulatory Commission initiated directives to NERC to develop reliability standards associated with extreme cold weather to improve the reliability and resilience of the bulk power system. See, e.g., FERC News Releases, "FERC Approves Extreme Cold Weather Reliability Standards, Directs Improvements," February 16, 2023.

62 Canadian Centre for Cyber Security, 2025-2026 National Cyber Threat Assessment, at 3.

63 *Id.*, at 25-26.

64 Emera Press Release, "Emera and Nova Scotia Power Responding to Cybersecurity Incident," April 28, 2025.

65 Business News Today, "Nova Scotia Power Cyberattack: What the ransomware breach reveals about utility cybersecurity in 2025," May 24, 2025.

66 *See*, e.g., Nuclear facility cybersecurity standards are included in CSA N290.7:21, published in January 2021; and Canada Bill C-8, with its increased requirements for "Designated Operators," including generators and nuclear facilities.

67 NERC, "2025 ERO Reliability Risk Priorities Report," at 7.

68 *Id.*, at 8.

requiring updates to its existing processes and the development of new initiatives to ensure compliance.[69]

6. Regulatory Risk

A utility's regulatory framework is an important consideration for both equity and debt investors. Regulatory risk is a key component of business risk for regulated utilities. For instance, S&P Global, in its rating methodology for regulated utilities, states "[t]he regulatory framework/regime's influence is of critical importance when assessing regulated utilities' credit risk because it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[70] Moody's, in its rating methodology for regulated electric and gas utilities, lists "Regulatory Framework" as one of four key factors that are important in Moody's assessment of ratings in the regulated electric and gas utility sector.[71] Moody's states that "[a]n over-arching consideration for regulated utilities is the regulatory environment in which they operate. The nature of regulation can vary significantly from jurisdiction to jurisdiction,"[72] and the agency assigns "Regulatory Framework," together with "Ability to Recover Costs and Earn Returns," a 50% factor weighting in its ratings scorecard.

Utility regulation is generally found by rating agencies and investors to decrease risk, all else equal, compared to competitive ventures. As stated by S&P, "[u]tility regulation, no matter where on the continuum of our assessments, strengthens a utility's business risk profile, and generally underpins our ratings."[73] S&P further notes that "[w]e therefore designate all these [North American] jurisdictions on a continuum from credit supportive to most credit supportive. These descriptions vary only in degree."[74] In its assessment of North American regulatory jurisdictions, S&P assesses Ontario as "Most credit supportive (strong)." Other "Most Credit Supportive (Strong)" provinces and states include British Columbia, Quebec, Alabama, Florida, Iowa, Kentucky, Michigan, and Wisconsin.[75] Because of their comparatively strong business risk profiles, underpinned by rate-regulated utility revenues, Canadian and U.S. utilities, including OPG, are typically afforded higher

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69 See the "Milestone Spreadsheet," accessible at https://www.ieso.ca/sector-participants/system-reliability/applicability-criteria-for-compliance-with-reliability-requirements.
70 S&P Global, "Key Credit Factors for the Regulated Utilities Industry," November 19, 2013, at 6.
71 Moody's Ratings, Rating Methodology: Regulated Electric and Gas Utilities, August 6, 2024, at 2 and 8.
72 *Id.*, at 7.
73 S&P Global, "North America Utility Regulatory Jurisdictions Update: Ontario Remains Unchanged, Notable Developments Elsewhere," March 11, 2024, at 3.
74 *Id.*, at 2.
75 *Id.*, at 4-5.

credit ratings than they would be if they operated in competitive markets, even when utilities have financial profiles that contain relatively high levels of debt.

As discussed above, 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. As discussed in Section 5, large nuclear construction projects in other jurisdictions have also been able to use different forms of CCR of financing costs, albeit those jurisdictions have allowed CCR at the utilities' full weighted average cost of capital ("WACC"), inclusive of an equity return.

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).

Other developments affecting OPG's regulatory risk both positively and negatively include:

- 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.[76]
- 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 increases for Ontario public sector employees, and which limits OPG had reflected in its revenue

[76] EB-2020-0290, Decision and Order, November 21, 2021, at 35.

requirement in EB-2020-2090.[77] OPG estimated the incremental cost impact of this repeal to be approximately $188 million.[78]

- In 2024, OPG reached a complete settlement on its deferral and variance account clearance application (EB-2023-0336) as approved by the OEB.[79]
- In 2024, the OEB's decision in the generic cost of capital proceeding reduced Ontario utilities' authorized base ROE by 25 basis points.[80]

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. 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 use CCR of interest on CWIP for nuclear construction for PRP is also seen as credit positive due to the improved near-term cash flows.

The following are more detailed findings by the major credit rating agencies with regard to OPG's regulatory framework:

- **Moody's:**
  - 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… 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

77 OEB, "Ontario Energy Board issues decision on Ontario Power Generation's Motion to Review and Vary the EB-2023-0098 Decision and Order," October 25, 2023.
78 *Id.*, at 8.
79 EB-2023-0336 Decision and Order, June 13, 2024.
80 EB-2024-0063, Decision and Order, at 45-46.

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 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."
- "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."[81]

- ***DBRS:*** "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."[82]

- ***S&P:*** "Our assessment on OPG's business risk incorporates its mostly low-risk, regulated operations under the generally supportive regulatory oversight of the Ontario Energy Board (OEB), its effective management of regulatory risk, its limited regulatory and geographic diversity, and its exposure to execution risk related to the refurbishment of its legacy nuclear generation plant. The company generates about 70% of its consolidated EBITDA from its business regulated by the OEB, which we view as a generally constructive regulatory environment. We expect OPG will continue managing its regulatory risk and benefit from

81 Moody's Ratings, "Ontario Power Generation Inc.," June 30, 2025, at 4-5.
82 DBRS Morningstar, "Ontario Power Generation Inc.," April 21, 2025, at 3.

> credit-supportive regulatory mechanisms, including an incentive ratemaking methodology for hydroelectric and a custom incentive regulation framework for nuclear."[83]

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. As noted, economic regulation for a generator reduces risk relative to competitive generators and Ontario continues to be viewed by S&P as being a "most credit supportive" jurisdiction. 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).

Because of the risk reducing aspects of regulation, Concentric has focused its market/industry FRS analysis described in Section 6 only on companies that are also subject to rate regulation and has further performed a screen to develop a proxy group of only companies that operate in "most credit supportive" jurisdictions, per S&P. In that section, Concentric also provides 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.

7. Financial Risk

Financial risk is an important component of a company's overall risk profile, and it relates to the way in which a company is capitalized. Financial risk, which is focused on solvency and liquidity, is often measured through analyses of relative capital structures as well as credit metrics. Further, a utility's credit rating provides a widely accepted opinion from a third-party credit rating agency of the utility's overall creditworthiness.

For our company-focused assessment, Concentric's consideration of OPG's financial risk focused on the review of assessments by the credit rating agencies and an analysis of *pro forma* credit metrics. This section also evaluates the CCR Regulation and its impact on financial risk. In addition, Concentric

83 S&P Global Ratings, "Ontario Power Generation Inc.," August 14, 2024, at 4.

considered evidence regarding OPG's cost of borrowing relative to other credit worthy Canadian utilities. In our market/industry assessment in Section 6, Concentric also considered OPG's capital structure compared to peer companies as an indication of relative financial risk.

OPG operates pursuant to rate regulation, which, as described above, is a featured factor referenced in credit rating agencies' risk assessments of the Company. Financially sound utilities have access to capital by virtue of their regulated business model. In addition, OPG's provincial ownership results in a three notch credit ratings "uplift" relative to OPG's stand-alone credit profile. There is evidence, however, that OPG's credit profile will be pressured over the upcoming rate period.

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. That consideration is consistent with the OEB's findings in 2009, where it stated:

> *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.*[84]

As such, while credit ratings and metrics provide evidence regarding financial risk and the financial integrity of a subject utility, they do not, in and of themselves, determine whether a given cost of capital meets the FRS.

Credit Rating Agency Assessments and Credit Metrics

OPG is rated A (low) by DBRS, BBB+ by S&P, and A3 by Moody's. As discussed above in the section on regulatory risk, the credit rating agencies view rate regulation as credit supportive and incorporate their views on OPG's regulatory environment into their ratings analyses. Another major factor that the ratings agencies have identified that impacts OPG's credit metrics and ratings is OPG's expansive CapEx program and the execution risk related to those programs. DBRS provides an example of the weighing of these considerations in its 2025 report on OPG, where DBRS states "[w]hile 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."[85] Other factors considered by the rating agencies include nuclear generation risks, political intervention risks, tariff and trade-related considerations, and the support of the Province.

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84 EB-2009-0084, Report of the Board, December 11, 2009, at 20.
85 Morningstar DBRS, "Ontario Power Generation Inc., April 21, 2025, at 2.

The rating agencies also discuss near-term credit pressure for OPG due to its capital program, with that pressure being somewhat mitigated by regulatory support (e.g., the CCR Regulation). For instance, DBRS states "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, which would reduce its debt needs."[86] In a similar vein, Moody's notes that "[t]here 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."[87]

The rating agencies note that a ratings upgrade for OPG is "unlikely"[88] or "highly unlikely,"[89] with Moody's stating that "[a]n upgrade is unlikely given the very high levels of execution risk associated with some of its upcoming nuclear capital expenditures."[90] Factors that could trigger a downgrade include deterioration in credit metrics below established thresholds for a prolonged period of time,[91] "[c]hallenges, delays or cost overruns related to its capital program,"[92] and a reduced probability or lack of support from the Province.[93]

86 *Ibid*.
87 Moody's Ratings, "Ontario Power Generation Inc., June 30, 2025, at 7.
88 DBRS, Moody's.
89 S&P.
90 Moody's Ratings, "Ontario Power Generation Inc., June 30, 2025, at 3.
91 Specifically, according to Moody's, a downgrade is possible for OPG if the Company's CFO/Debt ratio is forecast to fall below 15% on a sustained level (see, Moody's Ratings, Ontario Power Generation Inc., June 30, 2025, at 3), and, S&P has stated that it could lower OPG's rating over the next 12-18 months if its financial measures weaken, including FFO/Debt consistently below 13% (see, S&P Global Ratings, Ontario Power Generation Inc., August 14, 2024, at 3). In 2024, Moody's increased the downgrade threshold for CFO/Debt for OPG from 12% in previous credit reports (as recently as June 2024) to 15% in the most recent report in June 2025, making it easier for OPG to be downgraded, since for a given level of CFO, OPG can carry less debt overall; alternatively, a higher level of debt implies that OPG must have a higher level of CFO.
92 Moody's Ratings, Ontario Power Generation Inc., June 30, 2025, at 3.
93 See, e.g., Moody's Ratings, Ontario Power Generation Inc., June 30, 2025, at 3; Morningstar DBRS, Ontario Power Generation Inc., April 21, 2025, at 1.

The upcoming period of elevated CapEx for OPG will require OPG to have the opportunity to fully recover its costs, including an appropriate cost of capital, so that the Company can maintain sufficient financial strength to make the necessary investments related to the projected increased demand for electricity in Ontario.

CCR Regulation

The Ministry of Energy and Mines has published a proposal to amend O. Reg. 53/05 titled "Regulatory amendments to support financing for Ontario Power Generation's major nuclear projects."[94] The proposal identifies that OPG is taking steps to refurbish four units at Pickering, and, if passed, the CCR Regulation would establish a CCR mechanism to allow OPG to recover interest costs during the PRP. The proposal identifies that:

> *The proposed CCR mechanism for debt interest would support OPG's cash flow needs while the project construction is underway, thereby lowering borrowing requirements and associated costs. This change would reduce the long-term project costs to be recovered from ratepayers, generating significant overall ratepayer savings over the life of the projects.*[95]

Regulators and credit ratings agencies have noted the credit supportive nature of mechanisms such as CCR of interest cost on CWIP. For instance, the Federal Energy Regulatory Commission ("FERC"), in an order granting incentive rate treatments for a New England transmission line, found that:

> *[A]uthorizing 100 percent of CWIP [in rate base] will enhance the Applicants' cash flow, reduce interest expense, assist with financing, and improve the coverage ratios used by rating agencies to determine the Applicants' credit quality by replacing non-cash AFUDC with cash earnings. This, in turn, will reduce the risk of a downgrade in their debt ratings. Considering the size of the investment in the Project, we find that authorization of the CWIP incentive is appropriate.*[96]

Moody's also commented specifically on CCR of interest expense on CWIP for OPG:

> *[T]he 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*

94 https://ero.ontario.ca/notice/025-0501.
95 *Ibid*.
96 Federal Energy Regulatory Commission, "Order Granting Incentive Rate Treatments and Accepting Associated Tariff Amendments," Docket No. ER08-1548-000, November 17, 2008, at 35. In its order, FERC also approved a 125 basis points ROE incentive and the ability of the utility to seek recovery of costs in the event its project was cancelled.

> *portion of the SMR project to investors. Both measures would be credit positive for OPG, but the financial benefit depends on key assumptions.*[97]

Section 5 provides other examples of regulatory jurisdictions that have allowed for CCR of interest cost on CWIP, or "CWIP in rate base," for other large nuclear construction projects like the PRP. The ability of utilities to use CCR mechanisms is often a key financial underpinning of their projects, without which the utility would not proceed with that magnitude of investment. Notably, as discussed in Section 5, CWIP in rate base is often inclusive of both debt and equity costs, making such a practice more cash flow enhancing than the CCR Regulation.

Nonetheless, while not providing the extent of credit support offered by CWIP in rate base, CCR of interest expense on CWIP is credit supportive in that it provides incremental cash flow certainty during large utility construction projects, relative to the alternative of undertaking such projects without said support, and is also considered to be contributory to regulatory certainty and rate stability.

Credit Metrics

While the Board has previously found that "utility bond metrics do not speak to the issue of whether a ROE determination meets the requirements of the FRS,"[98] understanding the going-forward impact of different ratemaking assumptions on credit metrics can provide evidence regarding the financial integrity component of the FRS. In EB-2020-0290, OEB Staff's expert witness, London Economics International LLC, undertook an "illustrative forecast analysis, focusing on estimating credit metrics for the regulated assets only," and Concentric has provided a similar analysis in this proceeding, with certain modifications to more closely align the analysis with credit rating agencies' methodologies and to focus 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 a *pro forma* basis, reflect different measures of cash flow expressed as a percentage of the Company's long-term debt, based on a hypothetical/deemed capital structure for the regulated business, excluding the DNNP and thus provide a reasonable representation of financial flexibility and credit strength for the purposes of evaluating an appropriate capital structure for rate-setting purposes. The analysis is provided in Exhibit 1.

97 Moody's Ratings, Credit Opinion: Ontario Power Generation Inc., June 30, 2025, at 7.
98 EB-2009-0084, Report of the Board, December 11, 2009, at 20.

In their rating reports, the credit rating agencies provide thresholds for these key metrics that, if crossed, could cause a rating change. Specifically, the rating agencies provide the following ranges and thresholds for FFO/Debt (S&P) and CFO/Debt for OPG:

- S&P: "We also forecast FFO to debt of 14%-16%... We could lower our ratings on OPG over the next 12-18 months if its financial measures weaken, including FFO to debt consistently below 13%."[99]
- Moody's: "**Rating outlook**: It [OPG] will maintain a CFO pre-WC/debt ratio in the 15-20% range over the next few years... **Factors that could lead to downgrade**: A deterioration in financial metrics such that CFO pre-WC/debt is forecast to fall below 15% on a sustained basis."[100]

The figure below 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%. Red shading indicates the metrics are below threshold, while green shading indicates the metrics are above threshold.

Figure 10: *Pro Forma* Regulated-Only Credit Metrics

	2027	2028	2029	2030	2031
Key Credit Metrics at **45% Equity Thickness**					
FFO/Debt	12.4%	12.6%	12.6%	12.5%	12.6%
CFO/Debt	13.5%	13.9%	14.2%	14.0%	13.8%
Key Credit Metrics at **52% Equity Thickness**					
FFO/Debt	15.0%	15.2%	15.3%	15.2%	15.3%
CFO/Debt	16.7%	17.2%	17.5%	17.4%	17.1%

As shown in the figure, at a 45% equity thickness and based on a hypothetical regulated-only, deemed capital structure basis, FFO/Debt and CFO/Debt will consistently fall below the rating agencies' downgrade thresholds. 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

[99] S&P Global Ratings, Ontario Power Generation Inc., August 14, 2024, at 3.
[100] Moody's Ratings, Ontario Power Generation Inc., June 30, 2025, at 3.

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.

Credit Spreads

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[101] for indices of A-rated (i.e., for issuers with composite rating of A+, A, or A- ratings)[102] 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.

101 Measured as the difference between the new issue yield of ten and 30-year issuances over the yields on Government of Canada bonds of similar tenors.

102 "A" rated utilities utilized in the analysis include Hydro One Inc., Enbridge Gas Inc., EPCOR Utilities Inc., CU Inc., Toronto Hydro Corporation, and Alectra.

Figure 11: OPG Bond Spreads Compared to A-Rated Canadian Utilities (10-Year)[103]

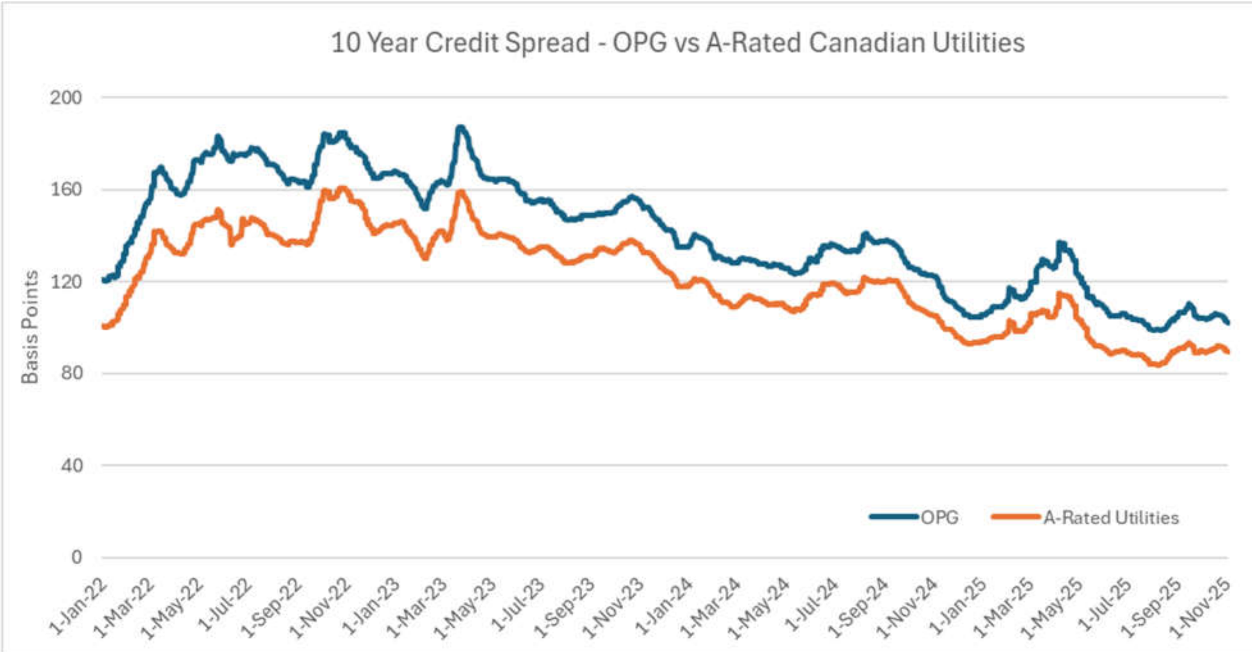
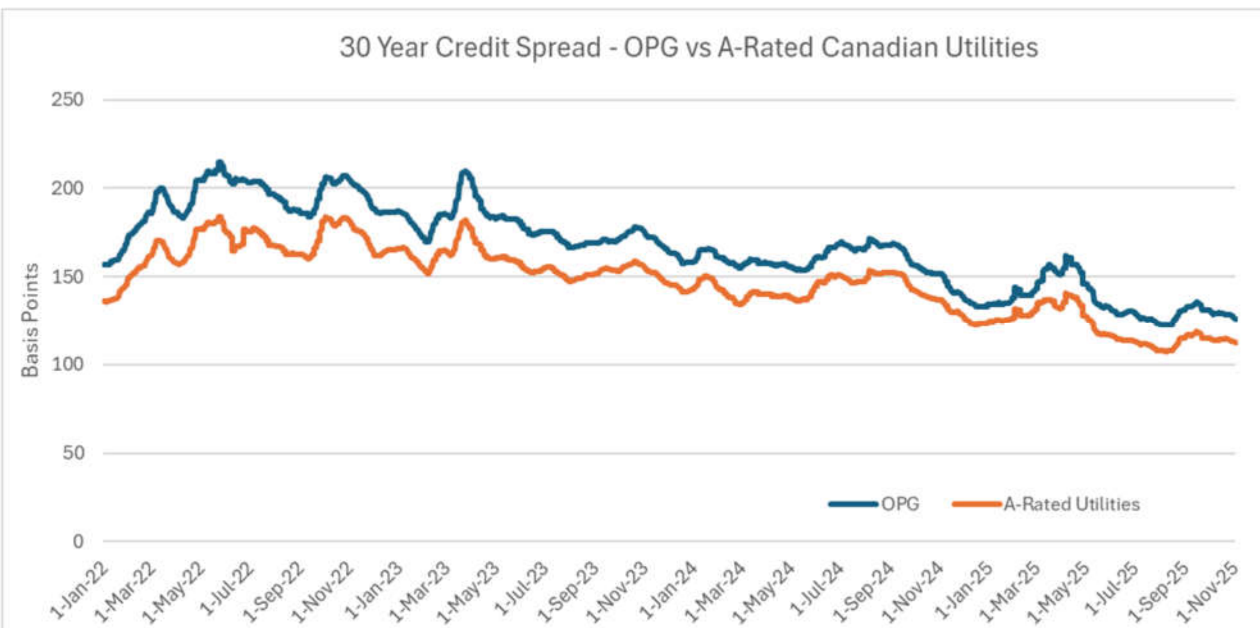


Figure 12: OPG Bond Spreads Compared to A-Rated Canadian Utilities (30-Year)[104]



103 Source: OPG and composite spreads 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.

104 Source for OPG and composite spreads 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.

8. Company-Focused Assessment Conclusions

With regard to the company-focused assessment, Concentric concludes that OPG's business and financial risks have increased since its EB-2016-0152 and EB-2020-0290 rate applications were filed and will continue to increase over the upcoming rate period. Concentric reaches this conclusion based on the following findings:

- Since the OEB's decision in EB-2016-0152 and continuing through the IR Term, OPG's assets and operations have become more focused on nuclear generation. OPG's CapEx and rate base reflects predominantly nuclear operations, and its equity ratio should be commensurate with the increased risk associated with nuclear generation.
- From a cost recovery perspective, OPG is at risk for variability in the output at its nuclear plants, a factor that distinguishes OPG from other North American regulated generators. In addition, OPG will also experience a decline in nuclear generation output due to the PRP over the upcoming rate period, which creates additional risk by concentrating the ability to recover costs and earn a return, for the nuclear business, on production from a single nuclear station for most of the IR Term.
- The driver of the Company's overall increase in rate base is OPG's undertaking of several major capital programs and projects. OPG's 2027-2031 capital expenditures on these programs and projects will be twice as large as the 2022-2026 forecast total and 3.5 times as large as the 2017-2021 total. OPG's largest project, the PRP, carries higher risks than the DRP, reflecting its cost, complexity, scope and overlapping schedule.
- There are increased operational risks related to the aging of Darlington nuclear and hydroelectric facilities. While the DRP replaced Darlington's core life-limiting components, there are emerging equipment issues at the station that need to be addressed to avoid risks to the asset and ensure reliable post-refurbishment operations. The hydroelectric fleet in general is of advanced aged, posing increased risks to safety and reliability. It requires a renewal of turbine generators and civil infrastructure, among others, at a level not previously seen by OPG.
- 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.
- OPG is subject to rate regulation, which decreases cost recovery risk for the Company relative to if it were a non-regulated entity, but not relative to its peers, who are also rate regulated.

The CCR Regulation will improve near-term cash flow, reducing financial risk, but only relative to the already elevated risk of the PRP. On balance, OPG's regulatory risk has remained relatively stable since its 2016 and 2020 rate applications, with some aspects of the risk decreasing and others increasing.

- The above-described factors also affect the Company's financial risks. In particular, while commenting on the credit-supportive nature of rate regulation for OPG, credit ratings agencies focus on OPG's capital plan as a source of significant risk.
- In terms of the "financial integrity" component of the FRS, OPG's financial risk will increase in the period from 2027 to 2031, as illustrated by the pressure on cash flows in the period due to the elevated CapEx program.
- OPG is perceived from a financial perspective to be of higher risk than similarly rated utilities, as demonstrated through an analysis of credit spreads that indicates that bond investors require a higher credit spread premium when investing in OPG bonds.

Concentric concludes that, taken as a whole, the shift in the Company's risk profile since the time of EB-2016-0152 and EB-2020-0290 warrants a reassessment of OPG's deemed equity ratio. In the following sections of this report, Concentric turns towards its market/industry assessment of industry trends and evidence regarding capitalization ratios of peer utilities.

SECTION 5:

MARKET/INDUSTRY ASSESSMENT: INDUSTRY PATHWAYS TO SUPPORTING INCREASING ELECTRICITY DEMAND, ENERGY SECURITY, AND THE ENERGY TRANSITION

As discussed in the previous section, Ontario's growing trend in electricity demand is being experienced globally, and legislatures, regulators, and utilities are identifying both the investment plans that are needed to meet demand, and the regulations and cost recovery mechanisms that will support those plans. In Ontario, those regulations and recovery mechanisms include the nuclear-specific provisions of O. Reg. 53/05, including the CCR Regulation and deferral and variance accounting. To place the Ontario-specific regulations and mechanisms in context, Concentric evaluated cost recovery and capitalization approaches taken in other North American jurisdictions that have or are investing in large nuclear plant construction projects. This review provides a foundation from which to consider and place in context both OPG's cost of capital, as well as the regulatory mechanisms (such as CCR) available to OPG as it moves forward with its large capital investments in Ontario's electricity system.

A. Approaches to Cost Recovery for Nuclear Generation Projects

1. Nuclear Construction Recovery Mechanisms

Provisions of O. Reg. 53/05 provide important protection and support to OPG as it advances large investments in nuclear power. For instance, O. Reg. 53/05 had reduced the company's future recovery risk by establishing the overall need for the DRP in the regulatory context and requiring the OEB to authorize recovery of incurred DRP costs, subject to a prudence review. O. Reg. 53/05 also requires the OEB to authorize recovery of incurred PRP (or any other regulated asset refurbishment) costs, subject to a prudence review.

Regulatory support for large-scale nuclear generation projects, however, is not unique to Ontario. For instance, 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*

25 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.[105]

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.[106]

Concentric finds that risk reducing properties similar to those found in O. Reg. 53/05, including the CCR Regulation, are also or have been present in other jurisdictions that have undergone large-scale nuclear construction projects, including among the proxy companies considered by Concentric in Section 6, and thus are taken into account in our recommendations for OPG's deemed equity ratio.

To perform this assessment, Concentric compared O. Reg. 53/05 from a risk mitigation perspective to similar legislation and regulatory rules that have enabled nuclear construction in other jurisdictions, focusing on whether: 1) the relevant regulator must approve 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) the utility is allowed to recover prudently-incurred construction and financing costs before the plant goes into service; 3) the utility is allowed to recover costs that exceed the originally approved projections, subject to a prudence review by the regulator; and 4) the utility is able to recover prudently incurred construction costs if the project is abandoned. In particular, Concentric reviewed legislation in the following three jurisdictions where large scale nuclear projects have been completed (or abandoned): Georgia, South Carolina and Florida. The following is a brief summary of the relevant legislation and statutes in each jurisdiction.

105 Nuclear Energy Institute, "State Legislation and Regulations Supporting Nuclear Energy," January 2025, at 2.
106 *Id.*, 3.

Figure 13: Regulatory Support for U.S. Nuclear Plant Owners

Jurisdiction	Nuclear Cost Recovery Provisions
Florida	• Florida utilities may recover preconstruction and construction costs, including "carrying costs on the utility's projected construction cost balance associated with the nuclear or integrated gasification combined cycle power plant" through the Capacity Cost Recovery Clause.[107] • "To encourage investment and provide certainty, associated carrying costs must be equal to the most recently approved pretax AFUDC at the time an increment of cost recovery is sought."[108] • Costs include Allowance for Funds Used During Construction accrued prior to construction, taxes, and O&M expenses. • Recovery is allowed before construction begins, provided the utility has obtained a determination of need and licensing. • If a project is abandoned, utilities may still recover prudently incurred costs over a period equal to the time costs were incurred or five years, whichever is longer. • Utilities must petition the Florida Public Service Commission at each stage (licensing, preconstruction, construction) for approval to proceed and recover costs.
Georgia	• Georgia Power used the Nuclear Construction Cost Recovery tariff to recover financing costs for Plant Vogtle Units 3 and 4. • "[A] utility shall recover from its customers… the costs of financing associated with the construction of a nuclear generating plant which has been certified by the commission prior to January 1, 2018. The financing charges shall accrue on all applicable certified costs as they are recorded in the utility's construction work in progress [CWIP] accounts pursuant to generally accepted accounting and regulatory principles as approved by the commission. The financing costs shall be based on the utility's actual cost of debt, as reflected in its annual surveillance report filed with the commission, and based on the authorized cost of equity capital and capital structure as determined by the commission when setting the utility's current base rates."[109] • The Georgia PSC retains authority to disallow costs if fraud, imprudence, or cost overruns are found. • Tariffs are updated annually.

107 https://www.flsenate.gov/Laws/Statutes/2020/366.93.
108 *Ibid.*
109 https://law.justia.com/codes/georgia/title-46/chapter-2/article-2/section-46-2-25/.

Jurisdiction	Nuclear Cost Recovery Provisions
South Carolina	• The Base Load Review Act ("BLRA") of 2007 allowed utilities to recover financing costs during construction, contingent on a prudency review.[110] • Allowed for the deferral and future recovery of project costs if the utility abandons the project. • The law was repealed in 2018 following the failed V.C. Summer nuclear expansion.

As described in Figure 13 above, the legislation and statutes in Florida, Georgia and South Carolina have included regulatory protection and assurance of cost recovery for nuclear construction projects comparable to that available to OPG through O. Reg. 53/05. As noted by Moody's regarding Georgia and nuclear operator Georgia Power, "[t]he Georgia regulatory framework continues to remain credit supportive, which is evident from historical regulatory decisions including the outcome of Georgia Power's 2022 general rate case as well as the continued support of the Vogtle project by the GPSC,"[111] and "[t]he utility's business risk has been mitigated throughout construction by a supportive regulatory and political environment as well as continued co-owner support, notwithstanding pending co-owner litigation."[112]

Additionally, all three of the jurisdictions allow recovery of prudently incurred financing costs for the projects prior to the plant entering service (*i.e.*, the utility is allowed to place CWIP in rate base and earn a cash return), similar to the proposed CCR Regulation that will be available to OPG under O. Reg. 53/05. On that basis, Concentric concludes that the regulatory mitigation for OPG for its nuclear construction programs is not unique to the Company, and that construction or refurbishment projects in other jurisdictions may not have been feasible without legislative and regulatory support. Further, because these states offer similar risk protection for nuclear projects, it is reasonable to compare the authorized equity ratios for these operating utilities to the deemed equity ratio for OPG. Concentric's analysis of comparable utilities in Section 6 includes data from developers of nuclear plants in those states. In addition, Figure 14 below provides the current authorized ROE and equity ratio, as of October 31, 2025, for companies in Concentric's main proxy group that operate in those states and own nuclear generation.

110 https://perma.cc/2T2V-4FDY.
111 Moody's Investors Service, "Georgia Power Company," October 5, 2023, at 6.
112 *Ibid*.

Figure 14: ROEs and Equity Ratios in Nuclear Supportive Jurisdictions

Utility	Authorized ROE	Authorized Equity Ratio
FP&L (Florida; owner of St. Lucie and Turkey Point)[113]	10.80%	59.60%
Duke (Duke Energy Carolinas, LLC in South Carolina; owner of Oconee, Catawba, and Robinson)[114]	9.94%	51.21%
Duke (Duke Energy Progress, LLC in South Carolina)[115]	9.60%	52.43%
Dominion (Dominion Energy South Carolina in South Carolina; owner of V.C. Summer)[116]	9.94%	52.51%
Georgia Power Company (Georgia; owner of Vogtle and Hatch)[117]	10.50%	56.00%

Concentric further observes that legislative protections related to nuclear construction projects have not eliminated recovery risk for utilities. Indeed, events in the nuclear construction industry in two of the above jurisdictions, South Carolina and Georgia, have, in fact, increased investors' perceived risk of such projects.

In particular, in South Carolina, SCANA had started construction of the V.C. Summer Plant under the Base Load Review Act ("BLRA"), which, as discussed below, provided regulatory support for cost recovery of new nuclear facilities during construction. The project experienced construction delays, cost overruns and the bankruptcy of the engineering, procurement and construction contractor (Westinghouse). This led SCANA to ultimately abandon the project in July 2017. SCANA sought recovery of its prudently incurred costs up to that time under the provisions of the BLRA. However, SCANA's credit rating was downgraded by S&P in September 2017 when the consumer advocate in South Carolina challenged the constitutionality of the BLRA, which was ultimately repealed by the South Carolina legislature, and SCANA was eventually acquired by Dominion Energy in order to avoid further financial distress.

113 Florida Public Service Commission, Florida Power & Light Co., Docket No. 20210015-ROE trigger, October 4, 2022.
114 Public Service Commission of South Carolina, Duke Energy Carolinas LLC, Docket No. D-2023-388-E, June 20, 2024.
115 Public Service Commission of South Carolina, Duke Energy Progress LLC, Docket No. D-2022-254-E, February 9, 2023.
116 Public Service Commission of South Carolina, Dominion Energy South Carolina, Docket No. D-2024-34-E, March 1, 2024.
117 Georgia Public Service Commission, Georgia Power Co., Docket No. D-44280, December 20, 2022.

In Georgia, Georgia Power undertook the construction of Vogtle plant units 3 and 4 after receiving Georgia Public Service Commission ("Georgia PSC") approval for the new nuclear facilities under the Georgia Nuclear Energy Financing Act. Originally anticipated to cost approximately $14 billion (USD) and take 7-8 years to construct, Georgia Power estimated the total cost after completion to be over $30 billion.[118] Georgia Power ultimately did not recover its full costs of Vogtle 3 and 4, entering into a stipulation with intervening parties to recover approximately 75% of its capital costs.[119]

The South Carolina and Georgia experiences demonstrate that, even with supportive legislation and regulation, investment risk related to the execution of large nuclear "megaprojects" is far from eliminated. For this reason, investors continue to consider large nuclear construction projects to be significantly risky, even when performed with the support of legislative initiatives or favorable cost recovery mechanisms.

118 Energy Information Administration, "Plant Vogtle Unit 4 begins commercial operation," May 1, 2024.
119 Moody's Investors Service, "Georgia Power Company," October 5, 2023, at 5.

SECTION 6:

MARKET/INDUSTRY ASSESSMENT: FAIR RETURN STANDARD ANALYSIS

A. Overview

As part of the FRS, the capital structure allowed in this proceeding should ensure that OPG can attract capital on reasonable and comparable terms. In this section, Concentric compares OPG's deemed equity ratio of 45% (the Company's deemed equity ratio since 2013) to several relevant proxy groups. This comparison demonstrates that OPG's authorized ratio of 45% lags the returns of its peers and does not adequately reflect the Company's heightened financial and execution risks resulting from its expansive capital projects over the coming rate plan.

B. Use of Proxy Company Analysis for Cost of Capital Determinations

Analyses of comparable, or "proxy," companies is a common and well-accepted approach used in the determination of the cost of capital for regulated utilities and for benchmarking business and financial risks. Proxy groups are used for the following main reasons in cost of capital determinations: (1) adherence to the comparable investment standard; (2) since the cost of capital is a market-based concept, and given that OPG is not a publicly-traded entity, it is necessary to establish a group of companies that is both publicly-traded and comparable to OPG in certain fundamental business and financial respects to serve as its "proxy" for purposes of the cost of capital evaluation process; and (3) even if OPG's regulated operations were held by a stand-alone publicly-traded entity, it is possible that transitory events could bias its market-determined cost of capital in one way or another over a given period of time. A significant benefit of using a proxy group is its ability to mitigate the effects of anomalous events that may be associated with any one company.

Regulatory commissions and cost of capital analysts generally apply a set of screening criteria in order to define a risk-appropriate group of comparable companies. For instance, the Federal Energy Regulatory Commission ("FERC") provides the following summary of its practice for selection of a proxy group for electric transmission companies:

> *Composition of the Proxy Group: In this section we address the following issues concerning the proper methodology for developing a proxy group and calculating the zone of reasonableness: (1) the use of a national group of companies considered electric utilities by Value Line; (2) the inclusion of companies with credit ratings no more than one notch above or below the utility or utilities whose rate is at issue; (3) the inclusion of companies that pay dividends and have neither made nor announced a dividend cut*

> *during the six-month study period; (4) the inclusion of companies with no major merger activity during the six-month study period; and (5) companies whose DCF results pass threshold tests of economic logic.*[120]

While the individual screens require modification based on the subject company to which proxy companies are being compared,[121] the goal of screening companies based on their risk characteristics increases both the comparability of the group and the confidence that the analyst (or regulator) can have in drawing conclusions based on analyses of the proxy group. Therefore, for consistency with the above considerations, Concentric relied on a screening process similar to one we typically apply in cost of capital analyses to narrow the list of potential companies in order to establish a proxy group of North American electric utility companies that are risk appropriate for comparison to OPG.

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. That determination must be based on an assessment of OPG-specific risks relative to the proxy group and informed judgment. For example, the National Energy Board (predecessor to the Canada Energy Regulator), in discussing the cost of capital for the TransCanada Mainline, stated, "[t]o the greatest extent possible, comparable companies have to face similar business risk as the Mainline. If they do not, judgment needs to be applied to the cost of capital estimates to reflect business risk differences."[122] In other words, whereas a subject company of average risk relative to the proxy group potentially would warrant an equity ratio equal to the average or median result of the proxy group, a company of greater risk potentially would warrant an equity ratio above the mean or median result, and conversely a company of lower risk potentially would warrant an equity ratio below the mean or median result.

In summary, the use of comparable companies to benchmark business and financial risks in the context of cost of capital determinations is common practice among North American regulatory jurisdictions, and it is a method Concentric has applied to our evaluation of OPG's capital structure. In the discussion that follows, we present Concentric's analysis of OPG's level of business and

120 Opinion No. 531, Order on Initial Decision, 147 FERC ¶ 61,234 (June 19, 2014), at 44-45.

121 For instance, the FERC applies a screen for the inclusion of master limited partnerships ("MLPs") in natural gas pipeline proxy groups that the MLPs derive at least 50% of operating income from, or have 50% of their assets devoted to, interstate operations (see, Opinion No. 510, Portland Natural Gas Transmission System, 134 FERC ¶ 61,129 (February 17, 2011), at 62.

122 National Energy Board RH-003-2011 Reasons for Decision, TransCanada PipeLines Ltd, NOVA Gas Transmission Ltd., and Foothills Pipelines Ltd., March 2013, at 165.

financial risk relative to a proxy group of electric utilities, as well as our review of equity ratios authorized for the proxy group to provide context for where, within a reasonable range, Concentric believes OPG's deemed equity ratio should be set by the OEB.

C. Selection of Proxy Companies

Concentric analyzed the equity ratios of a peer group of North American utilities to inform a range of reasonable deemed equity ratios for OPG. As discussed in Appendix C, there is strong precedent in Canada for considering North American proxy groups in cost of capital decisions. At the same time, Concentric is cognizant of the OEB's findings regarding the use of U.S. comparators in proceeding EB-2024-0063:

> *While it may be relevant to consider U.S. utility ROE results, differences in structure and risk limit the ability to find truly comparable companies. […]*[123]
>
> *The integration of U.S. and Canadian utility markets and the potential lure of higher returns for investors is a factor to be considered in arriving at a final conclusion concerning the requisite ROE that must be provided to meet the FRS. However, the use of U.S. regulated utility data as equivalent to Canadian regulated utility data in any computation is questionable. […]*[124]
>
> *In 2009, the heavy reliance on U.S. comparators was, in part, a response to the heightened uncertainty and financial distress that made it difficult to draw reliable conclusions from Canadian market data alone. Current financial conditions demonstrate that Canadian and U.S. financial markets have been stable and well-functioning, and any potential short-term volatility is unpredictable. Therefore, there may be less justification for placing the same degree of reliance on U.S. comparators, without discarding appropriate U.S. comparators out of hand.*[125]

In Concentric's experience, the integrated nature of North American capital markets, lack of a sufficient sample of comparators in Canada, and the similarities in rate regulation in Canada and the U.S. support the inclusion of U.S. proxy companies when analyzing the cost of capital for Canadian utilities. In addition, while the above findings from the OEB indicate the OEB's preference for the moderation of the reliance on U.S. comparators relative to the recent past, at least as it related to the generic cost of capital proceeding, it does not suggest that U.S. comparators should be ignored where they are appropriate. In OPG's case, there is good reason to turn to U.S. comparators. While there are

[123] EB-2024-0063, Decision and Order, at 37.
[124] *Ibid.*
[125] *Id.*, at 38.

no "truly comparable companies" for OPG in Canada or the U.S., there are few, if any, reasonably comparable companies in Canada, given, among other things, OPG's status as a "pure play" generator (as further discussed below). In Concentric's view, this necessitates the consideration of U.S. comparators in order to obtain representative market data and conduct an imperfect albeit meaningful market/industry assessment.

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. From that group, Concentric applied the following screens:

- **Own regulated generation assets that are included in rate base**. OPG's prescribed assets represent 100% rate-regulated generation, and companies in the proxy group should reflect the heighted risk profile of generating assets, especially as investors generally attribute higher risk to utilities with generation assets than those with only transmission or distribution operations.[126] This is highlighted in Moody's 2024 ratings methodology for regulated electric and gas utilities: "[w]e view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays;"[127]
- **Own regulated nuclear and/or hydroelectric generation**.[128] As noted earlier, OPG's rate regulated facilities consist of the Pickering and Darlington nuclear stations, as well as 54 hydroelectric generating stations. In addition, as discussed earlier, the OEB has recognized that nuclear assets are higher in risk than hydroelectric assets. Therefore, it is important to

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126 The OEB has had similar findings. For example, in EB-2007-0905, the OEB concluded: "OPG's nuclear business is riskier than regulated transmission and distribution utilities in terms of operational and production risk, but is less risky than merchant generation." In that same decision, the OEB also commented on the relative risk of generation as follows: "The Board has concluded that OPG is of higher risk than electricity LDCs, gas utilities and electric transmission utilities and of lower risk than merchant generation." *See*, EB-2007-0905, Decision with Reasons, November 3, 2008, at 149.

127 Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, August 6, 2024, at 14.

128 Excludes utilities with only a minimal (*i.e.*, less than 5% of their total generation portfolio) amount of nuclear or hydroelectric generation. A discussion of proxy group company nuclear risks is provided in Appendix B.

compare OPG against a group of companies that also own regulated nuclear and/or hydroelectric generation facilities;

- **Have regulated revenue and regulated net income that make up greater than 60% of total revenue and total income for the consolidated company.** This screen, in combination with the screen below regarding electricity revenue and net income, serves to exclude companies that do not derive a significant portion of their financial results from regulated electric operations while simultaneously including enough companies so that the resulting proxy group is not unduly small. While 60% is not a "bright line" percentage for separating regulated from non-regulated companies, including only those companies that derive more than 60% of their revenues and net income from regulated operations results in proxy companies that, like OPG, are generally protected by regulation rather than being subject to substantial merchant or market-related risks;
- **Have regulated electricity revenue and net income that make up greater than 80% of revenue and income for the consolidated company's regulated operations.** Including only those companies that derive more than 80% of their regulated revenue and net income from regulated electricity operations ensures that the proxy companies, like OPG, derive the predominant share of their financial results from regulated electricity segments. 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 its overall size; and
- **Have an investment grade credit rating similar to that of OPG.** As noted earlier, OPG has an "A (low)" issuer and unsecured debt rating from DBRS, a "BBB+" corporate and unsecured debt credit rating from S&P, and an "A3" senior unsecured debt rating from Moody's. As also noted earlier, S&P and Moody's rate OPG as "bb+" and "baa3" (*i.e.*, three notches below its corporate credit rating) on a stand-alone basis, before consideration of support by the Province. Since rating agencies incorporate an assessment of financial and business risks in their ratings, Concentric's credit rating screen selects electric utility companies with investment-grade credit ratings (an S&P credit rating of BBB- or above or a Moody's credit rating of Baa3 and above), which reduces the need to adjust the results to account for any perceived differences in business or financial risk compared to OPG. Further, selecting proxy

companies that, like OPG, have an investment grade credit rating ensures that the proxy companies are generally in sound financial condition.[129]

None of the publicly traded Canadian companies that Concentric reviewed met all of Concentric's screening criteria. Emera, Fortis, and Algonquin all failed the screening criteria of owning more than a minimal amount of regulated hydroelectric and/or nuclear generation.[130] Emera also failed, albeit marginally, the screen that each utility should have regulated electricity revenue and net income that make up greater than 80% of the consolidated company's regulated operations.[131] Algonquin also failed the screens that utility should derive greater than 80% of consolidated regulated revenue and regulated income from regulated electricity operations.[132]

In order to broaden the proxy group to include at least a minimal number of Canadian utilities, however, Concentric included Emera, Fortis, and Algonquin in the proxy group, as they otherwise met our screening criteria. This proxy group, comprised of the fifteen U.S. companies that met our screening criteria, along with the three Canadian companies noted above, formed Concentric's primary peer group (the "Concentric Proxy Group").

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). Figure 14 presents the holding company utilities that met each of the screening criteria for the Concentric Proxy Group, the Nuclear Group, and the Hydro Group. Exhibit 2 details how each peer company met the screening criteria above. Only the three Canadian companies failed to make either the Nuclear Group or the Hydro Group. In addition, as described below, Concentric also considered a subset of utilities in the Concentric Proxy Group that operate in S&P's "most credit supportive" jurisdictions, in recognition of the OEB's findings in EB-2024-0063 regarding the relative supportiveness of the Ontario regulatory framework.

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129 The only utilities removed from the proxy group due to this screening criterion were PG&E Corporation and Hawaiian Electric Industries, Inc, which have sub-investment grade credit ratings.

130 Fortis and Algonquin own minimal amounts of regulated hydroelectric and/or nuclear generation.

131 Emera had a 3-year average of 72% and 76% of regulated electric revenue and regulated electric income, respectively.

132 Algonquin owns 115 MW of hydroelectric generation according to its 2024 Annual Report and has 56% and 54% regulated electricity revenue and regulated electricity operating income, respectively.

Figure 15: Concentric Peer Groups

All Value Line U.S. Electric Utilities and Publicly-Traded Canadian Utilities

Application of screening criteria listed above

Hydroelectric Group

Company	Ticker
ALLETE, Inc.	ALE
Edison International	EIX
IDACORP, Inc.	IDA
Portland General Electric Company	POR
Southern Company	SO

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

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

D. Proxy Group Authorized and Actual Equity Ratio Analysis

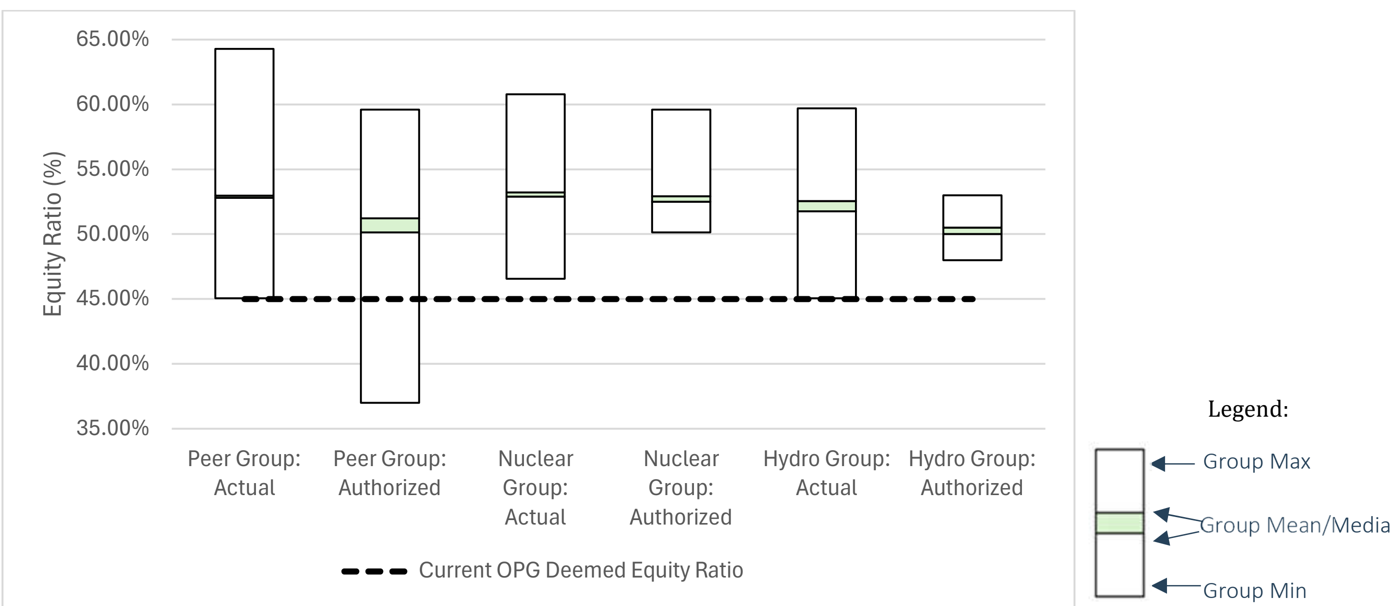
Concentric analyzed the equity ratios of the three North American proxy groups described above to help inform a range of reasonable deemed equity ratios that would provide OPG a fair cost of capital, consistent with the FRS. For each of these proxy groups, Concentric analyzed (i) the actual equity ratios based on five years of historical financial data at each holding company; and (ii) the current regulatory commission-authorized equity ratios for each operating company. The results of this analysis are provided in Figure 16 below.

Figure 16: Summary of Peer Group Analysis

	Concentric Proxy Group		*Nuclear Group*		*Hydro Group*	
Peer Group Equity Ratios	Actual	Authorized	Actual	Authorized	Actual	Authorized
Mean	52.97%	50.13%	52.89%	52.92%	51.75%	50.49%
Median	52.80%	51.21%	53.23%	52.50%	52.54%	50.00%
Central Tendency Range	50% - 53%					
Current OPG Deemed Ratio	45%					

Figure 16 above illustrates that *all* authorized and actual mean and median equity ratios across the three North American proxy groups are *above* OPG's current deemed equity ratio of 45%. Across all groups, the central tendencies of actual and authorized equity ratios ranged between 50% and 53%. As such, OPG's current deemed equity ratio is, at minimum, 5% below the lowest mean and median equity ratios for the proxy groups. Figure 17 below illustrates the range of equity ratios comprising each of the three proxy groups relative to OPG's current deemed equity ratio.

Figure 17: Fair Return Standard Analyses of Equity Ratios

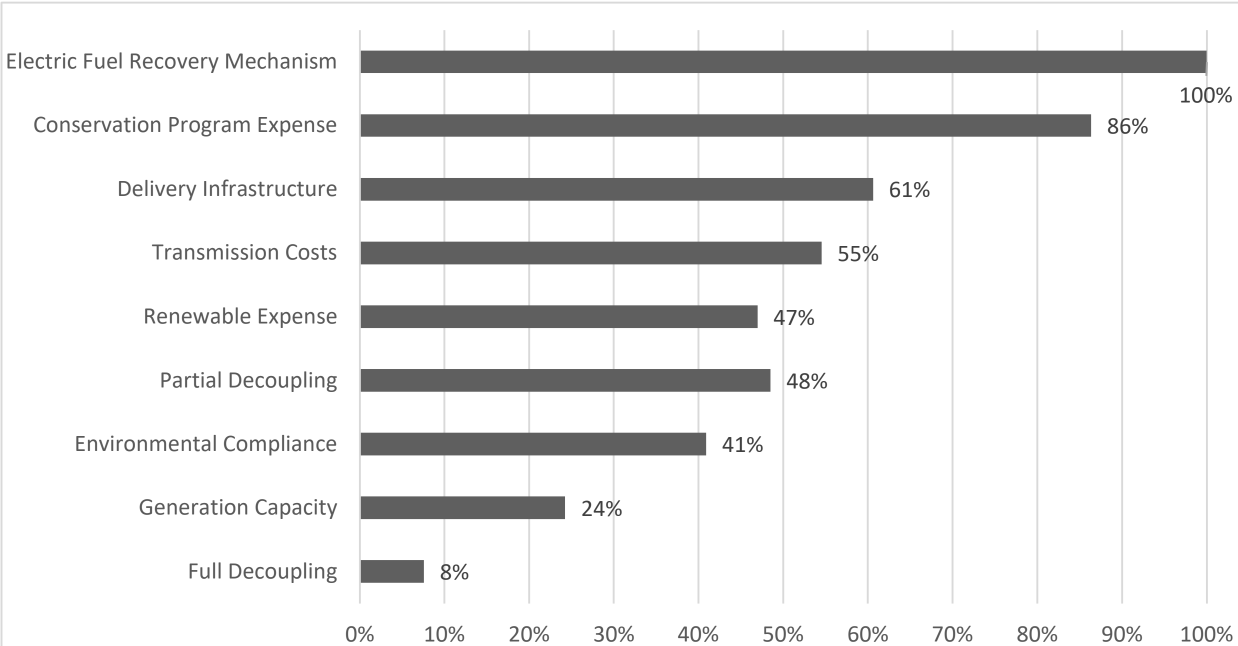


From a FRS perspective, Figure 17 illustrates that, in addition to being below the mean and median of the proxy groups, the current deemed equity ratio for OPG also falls at or below the *lowest* authorized and actual equity ratios of almost every proxy group, and in particular falls below the lowest authorized ratio of the Nuclear Group by 5%. In considering these results, it is worth emphasizing that none of these utilities are pure generation utilities and, on that basis alone, all have lower operating risk than OPG.

E. Proxy Group Adjustment Mechanisms Analysis

Concentric also compared the regulatory environment and structures within which the peer companies operate. In addition to the nuclear-specific legislative and regulatory support mechanisms discussed in Section 5, key regulatory items such as adjustment clauses and cost recovery mechanisms allow utilities to recover prudently incurred costs in a timely manner and reduce regulatory risk to investors. For the operating companies owned by the 18 holding companies in the Concentric Proxy Group and covered by S&P's Adjustment Mechanisms report, Concentric summarized the regulatory mechanisms available to each company. As summarized in Figure 18 below, all utilities have an electric fuel recovery mechanism available, if applicable, and most utilities have a conservation program expense and transmission cost recovery mechanism. In addition, nearly half of the peer operating utilities have environmental compliance or renewable expense cost recovery mechanisms. A minority of companies have "generation capacity" mechanisms available, which are generally either unit-specific mechanisms or blanket mechanisms covering items such as site selection costs, pre-construction costs, and cash returns on CWIP. 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.

Figure 18: Summary of Regulatory Mechanisms – Concentric Proxy Group



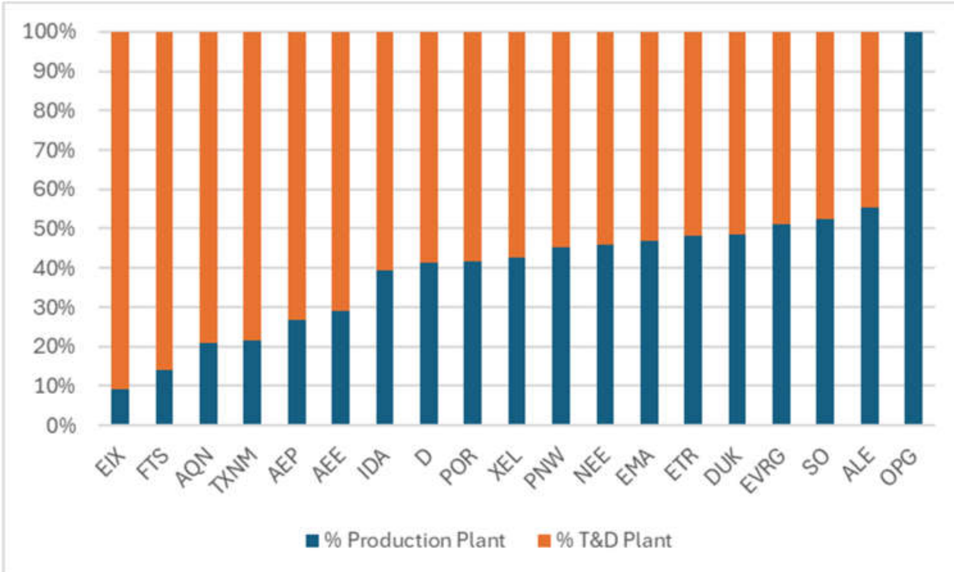
OPG's unique operational profile as a pure-play generator heightens the Company's risk due to the fact that, as discussed earlier, OPG is entirely at risk related to variability in the output of its nuclear facilities. Of the companies in the peer group that own generation, many mitigate output risk by recovering costs through a mix of fixed and variable charges, and/or have full or partial decoupling in place. For example, certain peer companies have weather normalization adjustments or mechanisms that true-up actual revenues to authorized revenues in the last rate case. OPG's regulated nuclear operations do not do so, raising OPG's volumetric risk relative to the peer companies.

As a broad measure of regulatory supportiveness, Concentric also screened the proxy companies for those that operate in S&P's "most credit supportive" jurisdictions, as described below.

F. Proxy Group Operating Profiles

Concentric analyzed the generation profiles of the peer group companies to determine comparability to OPG's operations. As summarized in Figure 19 below, the peer companies generally have a mix of generation and transmission/distribution assets. However, no peer company purely owns generation assets, as OPG does. In fact, as of 2024, no peer company has over 60% of its plant comprised of generation assets; ALLETE Inc. is the closest with a mix of 56% generation and 44% transmission and distribution ("T&D").

Figure 19: Generation vs. Transmission and Distribution Assets – Concentric Proxy Group



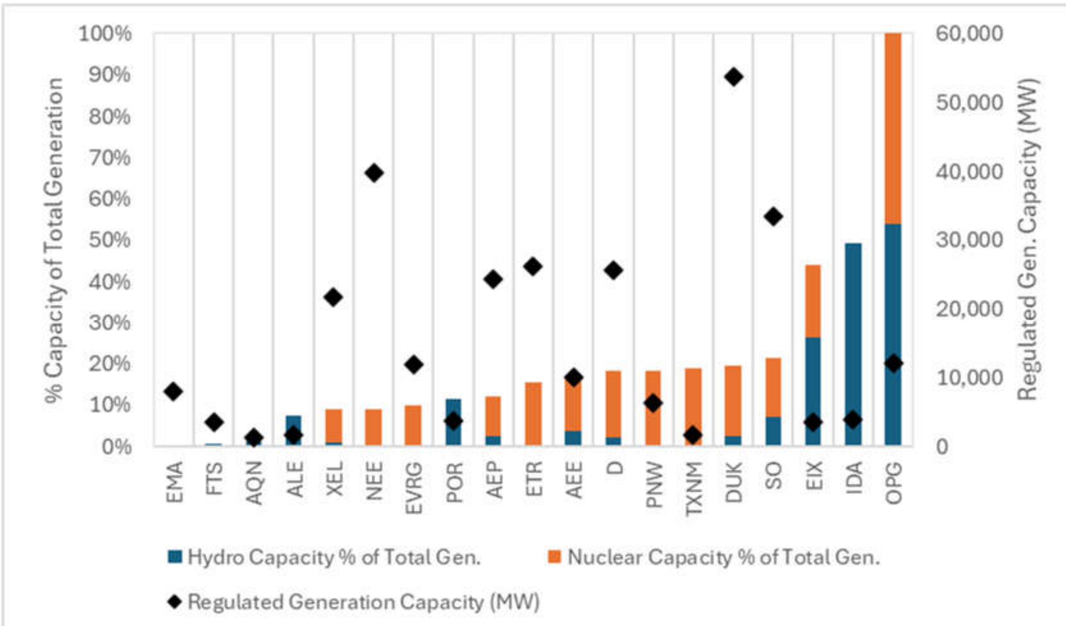
As discussed in the screening section above, the investment community generally considers the generation function to be higher risk than other regulated electric operations. The Board has previously agreed with this statement, concluding in EB-2007-0905 that: "OPG's nuclear business is riskier than regulated transmission and distribution utilities in terms of operational and production risk, but is less risky than merchant generation."[133] In the same decision, the OEB also commented on the relative risk of generation as follows: "…OPG is of higher risk than electricity LDCs, gas utilities and electric transmission utilities and of lower risk than merchant generation."[134] Since OPG's plant is 100% generation and the proxy group average is 38% generation, we conclude that OPG has higher risk than the proxy group in that regard.

Concentric also examined the technology type within generation plant for each peer company. As summarized in Figure 20 below, no peer company has over 50% of regulated generation capacity from hydroelectric and nuclear sources (represented by the blue and orange bars), whereas OPG's regulated capacity is comprised 100% of such sources. This indicates that no company in the main proxy group faces as much exposure to hydroelectric and nuclear-related risks as does OPG. IDACORP and Edison International are closest, at 49% and 44%, respectively, although these two companies have a smaller generation fleet in absolute MW capacity terms (represented by the black markers) and nuclear generation comprises less of their generation portfolios than it does for OPG. In MW capacity terms, OPG's regulated generation capacity of 12.1 GW is not the largest in the group;

133 EB-2007-0905, Decision with Reasons, November 3, 2008, at 149.
134 *Ibid.*

such companies as Duke Energy (53.7 GW), NextEra Energy (39.8 GW), and Southern Company (33.5 GW) have larger total generation capacity, but these three peer companies have less exposure to nuclear- and hydroelectric-related risks on a relative basis. Companies such as Emera Inc., Fortis Inc., Algonquin Power, and ALLETE Inc., have both minimal to no generation capacity nor exposure to nuclear and hydroelectric operations, and could be considered to be most differentiated from OPG on the basis of operating profiles.

Figure 20: Summary of Generation Capacity – Concentric Proxy Group



Concentric notes that the peer companies with the largest generating fleets (Duke Energy, NextEra Energy, and Southern Company) have comparatively higher authorized equity ratios relative to the broader peer group. For example, the operating companies of Duke Energy have authorized equity ratios ranging from 50.50% to 53.00%, NextEra Energy's regulated operating company is currently authorized a 59.60% equity ratio, and the operating companies of Southern Company range from having a 53.00% to a 56.00% authorized equity ratio. These three companies also have the largest nuclear generating fleets of the peer group in absolute terms, with NextEra Energy operating 3.6 GW, Southern Company operating 4.7 GW, and Duke Energy operating 9.2 GW of nuclear generation.

G. Proxy Group Financial Risk Analysis

In order to assess the financial risk of OPG relative to the proxy group, Concentric analyzed the allowed common equity ratios and actual book equity ratios for these companies.

The proxy group mean and median results are measures of central tendency for the proxy group from which inferences about a reasonable equity ratio can be made for OPG, after consideration of differences in risk profiles between OPG and the proxy group. Specifically, the mean is "generally the best measure of central location for purposes of statistical inference,"[135] while also being at risk of being "unduly influenced by extreme observations."[136] The median, or middle point of a set of observations at which half of the set of observations are above it and half and below it, is not subject to the same distortion due to extreme observations.[137] Figure 21 summarizes the results in tabular format for the Concentric Proxy Group. Exhibits 3 and 4 provide the analysis summarized in Figure 21.

Figure 21: Concentric Proxy Group Equity Ratios

Company	Holding Companies 5-Year Avg. Actual Equity Ratios (%)[138]	Avg. Authorized Equity Ratios (%)[139]
ALE	59.70	53.00
AEE	53.85	50.00
AEP	48.30	47.97
D	53.39	52.51
DUK	53.07	52.05
EIX	46.56	n/a
ETR	48.59	50.61
EVRG	59.43	50.13
IDA	52.54	50.00
NEE	60.79	59.60
PNW	50.90	51.93
TXNM	50.25	48.00
POR	45.07	50.00
SO	54.90	54.50
XEL	54.64	53.58
AQN	64.29	52.25
EMA	47.77	40.00
FTS	49.40	45.58
Mean	**52.97**	**50.69**[140]

135 Keller and Warrack, Statistics for Management and Economics, 5e ed., Duxbury Thompson Learning, 2000, at 92.
136 *Ibid*.
137 *Id*., at 93.
138 *See*, Exhibit 3. Represents five-year average of operating subsidiary actual capital structures, rolled up to the holding company level.
139 *See*, Exhibit 4. For each holding company, represents average operating subsidiary equity ratios authorized by their respective regulators. "n/a" indicates no subsidiary had an authorized equity ratio publicly-available.
140 Represents mean of holding companies' average operating subsidiary equity ratio. Mean of all operating subsidiaries is 50.13%.

Company	Holding Companies 5-Year Avg. Actual Equity Ratios (%)[138]	Avg. Authorized Equity Ratios (%)[139]
Median	**52.80**	**50.61**[141]
OPG	45.00	45.00

As shown in Figure 21, OPG's deemed equity ratio of 45% is lower than the average and median equity ratios Concentric identified for both authorized and actual proxy group equity ratios. OPG's deemed equity ratio is roughly 5 to 8 percentage points below the results of the analysis, depending on the analytical approach employed.

The only authorized equity ratios lower than OPG's are those for Emera and Fortis, both with lower risk T&D operations and no nuclear generation.[142] Certain U.S. companies produce analytical results close to OPG's deemed equity ratio, but these companies also have substantial T&D assets to diversify their generation risk. As discussed previously, generation assets are considered riskier from an investment perspective than T&D assets because, among other factors, generation assets typically have longer construction lead times, are subject to production risk and to risk from changes in environmental regulations and requirements and are more exposed to technological obsolescence.

As noted above, Figure 19 shows that 100% of OPG's assets are dedicated to generation, while the proxy group companies have a mixture of generation assets and T&D assets, and, on that basis, we conclude that OPG has higher business risk than the proxy group companies. This suggests a higher deemed equity ratio is appropriate for OPG.

With the lower deemed equity ratio of OPG compared to the proxy group companies, Concentric concludes that OPG has greater financial risk than the proxy group. Concentric also considers 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 suggests its deemed equity ratio should fall at the upper end of the proxy group.

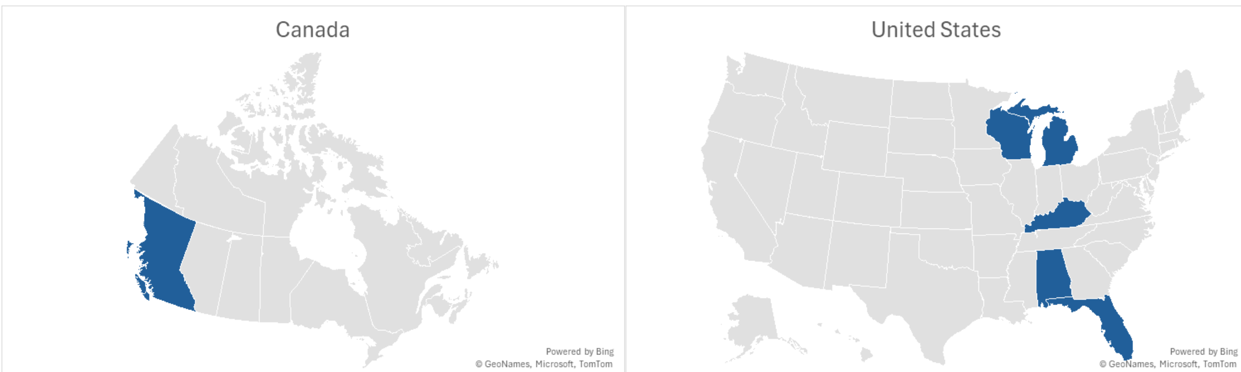
141 Represents median of holding companies' average operating subsidiary equity ratio. Median of all operating subsidiaries is 51.21%.

142 In addition, both Emera and Fortis have substantial Canadian operations, and Canadian utilities have historically been authorized lower equity ratios than their U.S. counterparts, an outcome that Concentric does not believe reflects the converged risk profiles of Canadian and U.S. regulatory jurisdictions, as discussed earlier.

H. Consideration of "Most Credit Supportive" Jurisdictions

In EB-2024-0063, the OEB found that "any increased risks [since 2009] have been at least mitigated by the OEB's regulatory approach, which S&P Global has classified as 'most credit supportive'."[143] Based on this finding, Concentric conducted an additional screen of its Concentric Proxy Group to consider only those utilities that operate in the "most credit supportive" jurisdictions in North America.[144] Figure 22 below illustrates the other jurisdictions in the U.S. and Canada that were included in the Most Credit Supportive Peer Group.[145]

Figure 22: Most Credit Supportive Jurisdictions in the Concentric Proxy Group



As shown in Figure 23 and Figure 24 below, this screening approach did not materially change the high end, mean, or median equity ratio results of the Concentric Proxy Group. Rather, screening for the most credit supportive jurisdictions had the effect of eliminating utilities that operate in Alberta, which represented the low end of the Concentric Proxy Group with 37% authorized equity ratios.

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143 Ontario Energy Board, Generic Cost of Capital proceeding, EB-2024-0063, March 27, 2025, at 10.

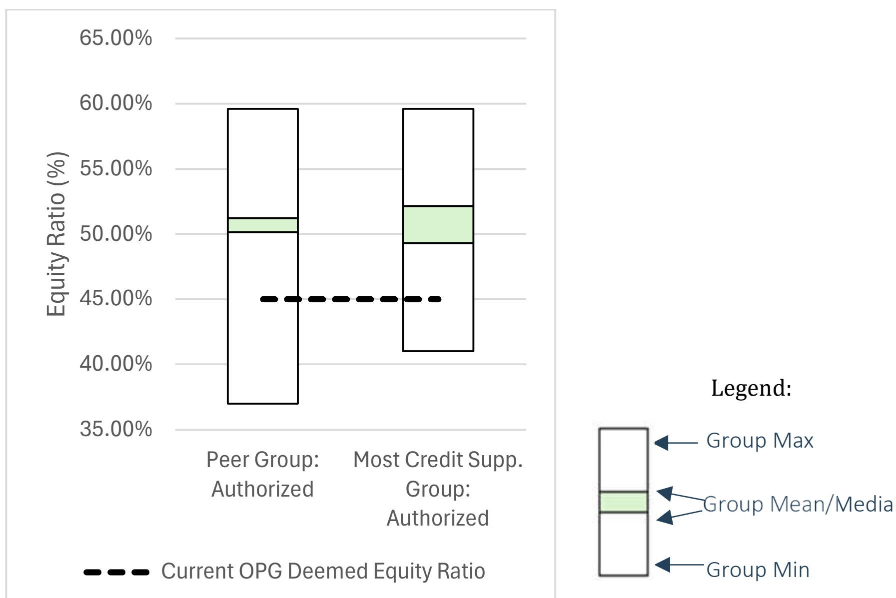
144 As classified by S&P Global Ratings. S&P Global Ratings assesses each jurisdiction's regulatory environment on a five-category scale, with "Most Credit Supportive" being the highest ranking.

145 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. For a full list of "most credit supportive" jurisdictions across North America, please see S&P Global Ratings' *North American Utilities Regulatory Jurisdictions Update: Connecticut And Mississippi Assessments Revised, Other Notable Developments*, February 19, 2025, at 4 and 5.

Figure 23: Equity Ratios – Concentric Proxy Group vs. "Most Credit Supportive" Jurisdictions

Authorized Equity Ratios by OpCo Jurisdiction	**Concentric Proxy Group**	**"Most Credit Supportive" Group**
Mean	50.13%	49.30%
Median	51.21%	52.15%
Min	37.00%	41.00%
Max	59.60%	59.60%

Figure 24: FRS Analysis of Equity Ratios – Concentric and "Most Credit Supportive" Proxy Groups



As noted previously, regardless of where the utility regulation falls on S&P's assessment spectrum, S&P considers any utility regulation as enhancing a utility's business risk profile, as compared to companies that are unregulated.[146] The differentiation of level of credit supportiveness by S&P stems from general regulatory stability, tariff-setting procedures and design, financial stability, and

[146] S&P Global Ratings' *North American Utilities Regulatory Jurisdictions Update: Connecticut And Mississippi Assessments Revised, Other Notable Developments*, February 19, 2025, at 2.

regulatory independence and insulation.[147] Concentric further notes that, while S&P recognizes the strength of the OEB's and other North American jurisdictions regulatory processes and stability, a ranking of "most credit supportive" does not mitigate all of the heightened risks that OPG and other utilities in "most credit supportive" jurisdictions may face, especially as it pertains to its specific business and financial risks. As such, the deemed capital structure and allowed cost of capital set in this proceeding should reflect a fair return commensurate with OPG's heightened risks, including as demonstrated by the results of the peer group analysis. In doing so, it should be recognized that substantial support, both regulatory and financial, is required for nuclear investments and large refurbishments, such as those included in OPG's capital plans. Nuclear investors will not move forward without legislative support or protective cost recovery mechanisms.

2. Conclusions

Concentric's proxy group analysis analyzed four different groups of companies: (1) the Concentric Proxy Group; (2) the Nuclear Group; (3) the Hydro Group; and (4) the "Most Credit Supportive" Group. Those analyses provided a range of central tendency of 50% to 53%, with a high end of the range of approximately 64%. OPG's unique business profile of 100% generation, its planned construction program, and its exposure to a 100% variable rate for nuclear production are considerable differentiators from other North American utilities, including those included in the proxy group analysis, indicating that OPG could reasonably be authorized an equity ratio towards the upper end of the range of analytical results. OPG's current deemed equity ratio of 45% is significantly below the ranges identified above despite OPG's elevated level of risk relative to the peer groups.

[147] *Ibid*.

SECTION 7:
SUMMARY OF FINDINGS AND CONCLUSIONS

This report provides Concentric's findings and recommendations regarding an appropriate deemed equity thickness for OPG in its next rate application with the OEB, which will cover the five-year period from 2027 to 2031. Concentric's analysis and conclusions are focused on whether the current cost of capital for OPG, inclusive of the capital structure, adheres to the FRS and meets the capital attraction, financial integrity, and comparability components of that standard.

To perform our evaluation, Concentric began with a company-focused assessment of OPG's business and financial risks and how they have changed over time. Concentric concludes based on our company-focused assessment that the significant change in the Company's risk profile since the time of EB-2016-0152 and EB-2020-0290 warrant a reassessment of OPG's deemed equity ratio.

Concentric then turned to a market/industry assessment from a cost of capital perspective, focusing squarely on the "comparability" component of the FRS. Concentric's market/industry assessment provides context for trends in the electricity industry related to increased capital spending for energy security and reliability, electrification and increasing electricity demand that are impacting electric utilities across North America. Because OPG has been and will continue to be competing for capital as the North America energy industry navigates these sector-wide trends, its authorized cost of capital needs to be commensurate with returns available at peers of similar risk.

In terms of the comparable return requirement of the FRS, Concentric conducted a series of screens based on OPG's operational profile to narrow down all publicly-traded North American investor-owned utility companies to those with similar operating characteristics to OPG. In doing so, Concentric compiled four proxy groups: (1) a main peer group; (2) a "nuclear" group; (3) a "hydroelectric" group; and (4) a peer group of utilities that operate in Standard & Poor's "most credit supportive" jurisdictions.

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 its financial risk relative to the proxy groups and the revenue risk it faces related to nuclear output variability. On this latter point, OPG's being entirely at risk related to variability in the output of its nuclear facilities distinguishes it from other utilities, as the companies in the proxy group do not face comparable risk.

As discussed in this report, the average range of equity ratios is from 49.30% to 52.97%, and the medians range from 50.00% to 53.23%. The upper bound for the proxy group results ranges from 53.00% to 64.29%. OPG's current deemed equity ratio of 45% is nearly 5% to 8% below the mean and median results, and 8% to over 19% below the upper end of the range of results. As discussed above, we believe OPG falls toward the upper end of the risk spectrum, reasonably supporting an equity ratio of 53% or higher to as much as 65% (*i.e.*, at the upper end of the proxy group results).

For this upcoming rate setting period, Concentric recommends an equity ratio of no less than 52% for OPG. This is somewhat higher than Concentric's recommended equity ratio of no less than 50% in EB-2020-0290 and 49% in EB-2016-0152, reflecting Concentric's assessment that OPG's risk profile reflects increased risk since those times. This recommendation balances considerations related to OPG's heightened risk profile and proxy group position with the Board's findings in EB-2016-0152 and EB-2024-0063, as discussed herein.

Appendix A:
SUMMARY OF OPG'S RATES APPLICATIONS

This is the sixth general rate setting proceeding before the Board for OPG. Below is a brief synopsis of the prior five proceedings, as well as the Board's findings in EB-2024-0063 regarding cost of capital matters.

EB-2007-0905

EB-2007-0905 was OPG's first cost of service application before the OEB, including cost of capital and capital structure. In its November 3, 2008 decision in EB-2007-0905, the OEB laid out the legislative requirements regarding rate regulation of OPG and reached numerous conclusions regarding its approach to setting rates for OPG.

With regard to the capital structure, the OEB stated: "The Board finds that the approach to setting the capital structure should be based on a thorough assessment of the risks OPG faces, the changes in OPG's risk over time and the level of OPG's risk in comparison to other utilities."[148] The OEB further 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,"[149] and that "Provincial ownership will not be a factor to be considered by the Board in establishing capital structure."[150] The OEB determined that a 47% equity ratio was appropriate for OPG, finding that OPG was of higher risk than any other Ontario energy utility but of lower risk than merchant generators.[151]

During EB-2007-0905, the OEB set one overall capital structure for both regulated hydroelectric and nuclear businesses but concluded that separate capital structures for the two businesses was an approach worth examining at the next proceeding.

At the time of EB-2007-0905, OPG owned and operated six prescribed hydroelectric generating stations (Sir Adam Beck I and II, Sir Adam Beck Pump Generating Station, DeCew Falls I and II, and R.H. Saunders), and three prescribed nuclear generating stations (Pickering A, Pickering B, and Darlington).

EB-2009-0084

In EB-2009-0084, the OEB reviewed its cost of capital policies for Ontario's regulated utilities to determine whether the automatic adjustment formula was continuing to meet the fair return

148 EB-2007-0905, Decision with Reasons, November 3, 2008, at 136.
149 *Id.*, at 140.
150 *Id.*, at 142.
151 *Id.*, at 149-150.

standard. As a result of its consultative process, the OEB affirmed its view that the fair return standard frames the discretion of a regulator, by setting out three standards or requirements (comparable investment, financial integrity, and capital attraction) that must be satisfied by the cost of capital determinations.[152] The OEB observed that meeting the fair return standard is not optional; it is a legal requirement.

In discussing the application of the fair return standard, the OEB made the following observations:[153]

1. "[T]he Board notes that the FRS [fair return standard] expressly refers to an opportunity cost of capital concept, one that is prospective rather than retrospective;"
2. "[T]he Board agrees with the National Energy Board which stated that '[i]t does not mean that in determining the cost of capital that investor and consumer interests are balanced;'"
3. "[A]ll three standards or requirements (comparable investment, financial integrity and capital attraction) must be met and none ranks in priority to the others;"
4. "[T]he Board reiterates that an allowed ROE is a cost and is not the same concept as a profit, which is an accounting term for what is left from earnings after all expenses have been provided for;"
5. "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;" and
6. "[T]he Board questions whether the FRS has been met, and in particular, the capital attraction standard, by the mere fact that a utility invests sufficient capital to meet service quality and reliability obligations. Rather, the Board is of the view that the capital attraction standard, indeed the FRS in totality, will be met if the cost of capital determined by the Board is sufficient to attract capital on a long-term sustainable basis given the opportunity costs of capital."

With respect to capital structure, the OEB found that its current policy for all regulated utilities, which was developed in March 1997, continued to be appropriate. The decision in EB-2009-0084 states:

[152] EB-2009-0084, Report of the Board, December 11, 2009, at i.
[153] *Id.*, at 19-20.

"As noted in the Board's draft guidelines, capital structure should be reviewed only when there is a significant change in financial, business or corporate fundamentals."[154]

The OEB also reiterated other policies, including that "the rate setting methodologies used by the OEB apply uniformly to all rate-regulated utilities regardless of ownership. The determination of the rate-regulated utilities' cost of capital is no exception."[155]

In 2016, the OEB issued an OEB Staff Report regarding the OEB's cost of capital policy. In that report, OEB Staff concluded that no changes were to be made to the policy at that time.[156]

<u>EB-2010-0008</u>

OPG's generation asset mix as of EB-2010-0008 was at approximately 38% nuclear and 62% hydroelectric, based on OEB-approved rate base for the prescribed facilities (excluding the lesser of nuclear asset retirement costs and unfunded nuclear liability), which was approximately the same as it had been as of EB-2007-0905. In its March 11, 2011 decision in EB-2010-0008, the OEB found that "there is no evidence of any material change in OPG's business risk and that the deemed capital structure of 47% equity and 53% debt, after adjusting for the lesser of Unfunded Nuclear Liabilities or Asset Retirement Costs, remains appropriate."[157]

In EB-2010-0008, there was a discussion of technology-specific costs of capital and capital structures. Certain experts recommended an equity ratio of 43% for the hydroelectric operations and an equity ratio of 53% for the nuclear operations, premised on OPG retaining its aggregate equity ratio of 47%. The OEB found that there was not enough evidence to support technology-specific capital structures and reaffirmed its findings in EB-2007-0905 that the risks related to nuclear generation are higher than those related to hydroelectric generation.[158]

In addition, while the issue was identified by the OEB in the context of technology-specific capital structures, the OEB recognized an emerging issue, noting that "[a]s the relative size of the hydroelectric and nuclear businesses changes (through major additions to rate base, for example) the issue will arise as to whether the overall ratio of 47% is to remain unchanged."[159]

154 *Id.*, at 49.
155 *Id.*, at 25.
156 EB-2009-0084, OEB Staff Report, January 14, 2016, at 1.
157 EB-2010-0008, Decision with Reasons, March 10, 2011, at 116.
158 *Id.,* at 116.
159 *Id.*, at 117.

EB-2013-0321

In EB-2013-0321, the OEB found that OPG's business risks had changed, primarily pointing to the addition of 48 hydroelectric assets to OPG's regulated assets and the then recently completed Niagara Tunnel Project. Specifically, the OEB found that the addition of hydroelectric assets and the Niagara Tunnel Project "increase the proportionate share of rate base related to hydroelectric facilities from about half in 2010 to approximately two-thirds now [*i.e.*, as of EB-2013-0321]."[160]

As a result of these findings, the OEB lowered the equity ratio for OPG from 47% to 45%. Specifically, the OEB stated, "…[t]he Board has determined that business risk has changed for this payment setting period, and that the business risk is reduced. The business risk is reduced because of the addition of significant hydroelectric assets to rate base, which are less risky than nuclear assets."[161]

In addition, the OEB found that, at the time of EB-2013-0321, moving to incentive regulation did not significantly increase risks to OPG such that the capital structure should be reset, noting that the capital structure for Ontario's electricity and gas distributors had not been reset when they moved to incentive regulation. The OEB did note, however, that part of its decision was based on the fact that OPG was not moving to incentive regulation in EB-2013-0321, and that "any potential changes to business risk this may entail could be considered in the incentive regulation proceeding."[162]

EB-2016-0152

The OEB left OPG's equity ratio unchanged at 45% in its decision and order in EB-2016-0152. The OEB continued to find that nuclear generation presents more business risks than hydroelectric generation, and that OPG's nuclear rate base would "increase substantially over the five-year term [of the period over which rates were being set],"[163] but noted that nuclear generated MWh will not increase relative to hydroelectric MWh. The OEB further found that OPG's nuclear-specific risks were mitigated by factors including "various protections provided by O. Reg. 53/05 and the variance and deferral accounts that allow OPG to recover substantially all their unexpected or unforeseen costs."[164] The OEB also found that the move to incentive regulation would not add significant risk to OPG noting that there was no new evidence to the contrary, and that given OPG's planning of the DRP and certain regulatory protections under O. Reg. 53/05, the risks of the DRP were also controlled. Additionally, the OEB commented on the use of U.S. companies in the proxy group for OPG, noting that Canadian

[160] EB-2013-0321, Decision with Reasons, November 20, 2014, at 113. Clarification added.
[161] *Id.*, at 114.
[162] *Ibid.*
[163] EB-2016-0152, Decision and Order, December 28, 2017, at 102. Clarification added.
[164] *Ibid.*

ratemaking equity ratios tend to be lower that U.S. ratemaking equity ratios and that, in EB-2016-0152, an adjustment should have been made to the U.S. companies' equity ratios to account for that divergence.[165] The OEB also noted that given its findings in the decision related to OPG's plan for Pickering extended operations beyond 2020 and the regulatory protections under O. Reg. 53/05, the associated risks, including a determination that Pickering extended operations may not proceed, were unlikely to materialize.[166]

EB-2020-0290

In EB-2020-0290, the OEB approved a settlement proposal by the parties that resolved cost of capital issues in that case.[167] Specifically, the settlement agreement included the continuation of OPG's deemed capital structure of 45% common equity and 55% debt. In addition, the authorized ROE for OPG was updated to reflect the Ontario formula ROE that was in effect at the time of the OEB's decision, which was 8.34%, for the rate years 2022-2026. The settlement also contained an earnings sharing mechanism based on the performance of OPG's combined nuclear and regulated hydroelectric business on an asymmetrical basis, with a 100-basis point deadband to the OEB-approved ROE rate and 50/50 sharing above the deadband, assessed over a cumulative five-year period from 2022-2026.[168]

EB-2024-0063

In EB-2024-0063, the OEB held a generic proceeding to determine cost of capital parameters to be used to set rates, effective January 1, 2025. In its March 2025 Decision and Order,[169] the OEB made a modification to the Ontario ROE formula that had the effect of reducing the authorized ROE by 0.25%, and made no changes to capital structure, among other findings. With respect to OPG specifically, the OEB's findings included that it would consider OPG's proposal regarding any changes to its capital structure in this payment amounts proceeding, should OPG choose to submit one.[170] Certain other findings from EB-2024-0063 that are relevant to Concentric's analysis in this proceeding are discussed in the body of this report.

[165] EB-2016-0152, Decision and Order, December 28, 2017, at 109.
[166] *Id.*, at 105.
[167] OEB Decision and Order in EB-2020-0290, November 15, 2021.
[168] *Ibid.*, see attached Schedule A, Settlement Proposal dated July 16, 2021, at 18.
[169] OEB Decision and Order in EB-2024-0063, March 27, 2025.
[170] *Id.,* at 55.

Appendix B:
NUCLEAR RISK – CREDIT RATING AGENCY PERSPECTIVES

This appendix provides excerpts from S&P Global Ratings highlighting that rating agency's views on the risk nature of utilities' nuclear businesses.

Ameren Corporation (AEE) – "[W]hile Ameren's size, diversity, and effective management of regulatory risk strengthen its credit profile, our assessment also incorporates the company's exposure to nuclear and coal generation. Nuclear generation increases operational risks and carries long-term storage concerns. This is risk is partly offset by the technology's emission-free generation… Environmental factors are a negative consideration in our credit rating analysis of Ameren because of its large exposures to nuclear and coal generation. This leads to heightened environmental risks, including the ongoing cost of operating older units in the face of disruptive technology advances and the potential for increasing environmental regulations that require significant capital investment."[171]

American Electric Power Company, Inc. (AEP) – "Heightened operational risk stemming from its ownership of the Cook nuclear plant… The company's exposure to nuclear generation introduces higher operational risks and plant retirement responsibilities. Social factors are a moderately negative consideration in our credit rating analysis based on the health and safety risks related to nuclear generation."[172]

Dominion Energy, Inc. (D) – "We generally view the building of SMRs as negative for credit quality since it entails potential construction risk due 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."[173] "We assess the merchant nuclear contracted asset as having the highest risk from the company's portfolio of contacted assets. The merchant nuclear exposes the company to higher operating risks, volumetric risks, counterparty credit risk, and commodity risks…DEI has begun closing coal-fired plants. However, its nuclear power generation also exposes the company to potential waste, health, and safety risks, despite a track record of effectively managing its nuclear fleet."[174]

171 S&P Ratings Direct, "Ameren Corp.," April 16, 2025.
172 S&P Ratings Direct, "American Electric Power Co. Inc.," September 19, 2023.
173 S&P Ratings Direct, "Dominion Energy Inc.'s Announcement To Explore SMR Nuclear Advancement Has No Immediate Credit Implications," October 22, 2024.
174 S&P Ratings Direct, "Dominion Energy, Inc," March 31, 2023.

Duke Energy Corporation (DUK) – "[T]he company's carbon-free nuclear generation portfolio increases its operating risk and exposes it to longer-term nuclear waste storage risks despite the company's long-term track record of achieving safe operational standards of its nuclear fleet."[175] "Environmental factors are a negative consideration in our credit rating analysis of Duke… Duke's nuclear power generation also exposes it to potential waste, health, and safety risks."[176]

Entergy Corporation (ETR) – "Environmental factors are a negative consideration in our credit rating analysis of Entergy because the company has exposure to coastal regions and extreme weather and nuclear generation…Social factors are a moderately negative consideration in our credit rating analysis based on the health and safety risk due to nuclear generation."[177]

Evergy, Inc. (EVRG) – "Our assessment also incorporates Evergy's exposure to nuclear and coal generation. Nuclear generation increases operational risks and carries long-term spent nuclear fuel storage concerns… Environmental factors are a negative consideration in our credit rating analysis of Evergy. This is due to the company's nuclear and coal generation exposure – its consolidated exposure to nuclear is 7% and coal is 38% of total generating capacity… Finally, social factors are a negative consideration in our credit rating analysis because of the health and safety risks associated with the company's nuclear generation."[178]

Pinnacle West Capital Corp (PNW) – "Environmental risks and potential liabilities associated with the company's coal-fired and nuclear generation capacity…Pressuring our assessment of PWCC's business risk profile is its limited regulatory diversity, Arizona's historically challenging regulatory construct, exposure to wildfire risk, environmental risks associated with the company's coal-fired generation, and operating risks associated with nuclear generation. As of Dec. 31, 2024, APS owns or leases 6,540 megawatts of generating capacity, of which about 38.2% is from nuclear and coal-fired fuel sources. We therefore assess PWCC's business risk profile at the very low end of its category relative to peers. We assess a negative comparable rating analysis modifier to incorporate this assessment."[179]

Southern Company (SO) – "[O]ur assessment also incorporates Southern's exposure to coal and nuclear generation and their associated higher environmental and operational risks. Currently,

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175 S&P Ratings Direct, "Duke Energy Corp. And Subsidiaries Outlooks Affirmed Following Atlantic Cost Pipeline Exit; Outlook Stable," July 9, 2020.
176 S&P Ratings Direct, "Tear Sheet: Duke Energy Corp. Can Maintain Credit Quality Amid Extensive Storm Restoration Costs," October 3, 2024.
177 S&P Ratings Direct, "Entergy Corp.," August 8, 2025.
178 S&P Ratings Direct, "Evergy Inc.," August 7, 2024.
179 S&P Ratings Direct, "Pinnacle West Capital Corp.," March 26, 2025.

coal contributes approximately 19% of its generation mix, and nuclear constitutes approximately 12%... The company's nuclear power generation also exposes it to waste, health, and safety risks despite its long record of effectively managing its nuclear fleet."[180]

"The upgrade on Southern Co. reflects our expectation of decreased construction risk given the completion of nuclear power plant, Vogtle Unit 4. Construction of Vogtle Units 3 and 4 began in 2009 and was originally slated to be completed by 2018. However, commercial operations of the units were significantly delayed, reflecting significant project setbacks and cost overruns. During this period, S&P Global Ratings-downgraded Southern and its subsidiaries by two-notches, reflecting increasing construction and execution risks and rising costs for these nuclear power plants. Vogtle Unit 3 began commercial operation in July 2023. The commencement of Vogtle Unit 4's commercial operations, concludes the company's higher-risk construction phase that has constrained its credit quality for more than decade."[181]

Xcel Energy Inc. (XEL) – "Key risks [include] operating risks associated with nuclear and coal plants…Our assessment also incorporates Xcel's exposure to coal and nuclear generation. Xcel's utilities source their electric generation from natural gas (33%), coal (15%), and carbon-free sources, including renewables (42%) and nuclear (10%). Nuclear generation increases operational risks and carries long-term nuclear fuel storage concerns, but it provides generation free of emissions."[182]

[180] S&P Ratings Direct, "Southern Co.," November 5, 2024.
[181] S&P Ratings Direct, "Southern Co. Upgraded to 'A-' On Commercial Operations of Nuclear Power Plant; Various Actions Taken on Subsidiaries," May 2, 2024.
[182] S&P Ratings Direct, "Xcel Energy Inc.," July 2, 2025.

Appendix C:
PRECEDENT FOR CONSIDERING U.S. DATA

Canadian regulators have adopted a pragmatic view of the use of U.S. data and proxy groups to estimate the authorized ROE for Canadian regulated utilities. The development of a proxy group comprised entirely of Canadian regulated utilities is challenged by the small number of publicly-traded utilities in Canada and the fact that many of those Canadian companies derive a significant percentage of revenues and net income from operations other than regulated electricity generation service. The continuing trend toward mergers and acquisitions in the utility industry, both within Canada and across the border with U.S. utility holding companies, further blurs the distinction between a Canadian and U.S. utility company. Multiple regulatory authorities in Canada have recognized that Canadian utility companies are competing for capital in global financial markets and that Canadian data are limited by the small number of publicly-traded utilities. Regulators have also recognized the integrated nature of Canadian and U.S. financial markets, which is evidenced by Canadian and U.S. utilities issuing securities in each other's countries, and the similarity of the utility regulatory regimes.

In particular, both the BCUC and the Alberta Utilities Commission ("AUC") have accepted the use of a North American proxy group comprised of utility companies in both Canada and the U.S. to set the authorized ROE for utilities under their jurisdiction. The BCUC explained its rationale for using a North American proxy group as follows:

> *For the reasons outlined above, we find the use of the Canadian proxy groups and US proxy groups alone to be inferior to that of using a North American proxy group which has a reasonable mix of both Canadian and US comparators, and the averaging of the results of these three groups to be a poor compromise. On balance, we find that having a proxy group of North American comparators trumps any jurisdictional or structural differences. In making this determination, we rely on the facts that financial and capital markets are highly integrated and that utility regulatory regimes in North America are sufficiently similar for the purpose of establishing a comparable ROE.*[183]

The BCUC decision is consistent with Concentric's experience that equity investors and credit analysts consider the utility industry as a North American industry, with Canadian companies competing for capital with similar risk companies in both countries. This is evidenced by, for

183 British Columbia Utilities Commission, Decision and Order G-236-23, September 5, 2023, at 16.

example, S&P assessing North American regulatory jurisdictions as a group, not separately by country.[184]

The AUC also developed a set of screening criteria for purposes of selecting a proxy group used to estimate the cost of equity for Alberta's electric and gas utilities.[185] The large majority of companies chosen by the AUC for the comparator group (28 out of 33 companies, or almost 85%) were either U.S. electric or U.S. gas utilities (or both). In addition, several of the Canadian companies in the AUC's comparator group have significant U.S. operations, including Emera, Fortis, and Algonquin Power.

In Ontario, the OEB's recent generic cost of capital decision questioned the framework it established in 2009 that placed reliance on U.S. proxy group data to establish the ROE for Ontario's utilities.

> *The OEB acknowledges that its 2009 Report placed considerable weight on U.S.-based utility data in establishing reasonable expectations for returns that enable Ontario-based utilities to access capital. The expert reports filed by both the EDA (Nexus expert) and OEA (Concentric expert) in this proceeding have been responsive to the approach previously adopted by the OEB therein, notably the comparability of U.S. and Canadian utilities. While it may be relevant to consider U.S. utility ROE results, differences in structure and risk limit the ability to find truly comparable companies.*[186]

While Concentric recognizes the challenges of finding comparable companies to Canadian utilities, these challenges exist for any utility in Canada or the U.S. The NEB recognized these challenges and reinforced this view in its bellwether TQM decision.

> *In light of the Board's views expressed above on the integration of U.S. and Canadian financial markets, the problems with comparisons to either Canadian negotiated or litigated returns, and the Board's view that risk differences between Canada and the U.S. can be understood and accounted for, the Board is of the view that U.S. comparisons are very informative for determining a fair return for TQM for 2007 and 2008.*[187]

Since the NEB's 2009 decision, the utility industry has become even more of a North American industry from both an investor and allocation of capital viewpoint. In Concentric's view, careful

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184 S&P Global, North American Utilities Regulatory Jurisdictions Update: Connecticut And Mississippi Assessments Revised, Other Notable Developments, February 19, 2025.
185 AUC Decision 27084-D02-2023, October 9, 2023, at para 99-104.
186 EB-2024-0063, Decision and Order, March 27, 2025, at 37.
187 RH-1-2008, March 2009, at 71.

screening of a North American proxy group of companies remains the most reliable method for determining the cost of capital, and is consistent with how investors see the market.

Appendix D:
RESUME OF DANIEL S. DANE

DANIEL S. DANE, CPA
PRESIDENT

Daniel S. Dane has more than 20 years of experience in the energy, utility, and financial services industries advising electric, gas, and water utilities, power generators, and natural gas pipelines in the areas of regulation and ratemaking, litigation, mergers and acquisitions, valuation, and regulatory accounting matters. Mr. Dane also provides expert testimony on regulated ratemaking matters and merger approval applications for investor- and provincially-owned utilities, including on multi-year rate plans and earnings sharing mechanisms, corporate finance matters such as the cost of capital and capitalization, merger impacts, revenue requirements, lead-lag studies/cash working capital, and regulatory policy. Mr. Dane has an MBA from Boston College in Chestnut Hill, Massachusetts, and a BA in Economics from Colgate University in Hamilton, New York. Mr. Dane is also a certified public accountant.

REPRESENTATIVE PROJECT EXPERIENCE

Ratemaking and Utility Regulation Assignments

Expert Testimony

- Submitted expert testimony on behalf of utilities and other stakeholders in state and provincial administrative rate setting and merger approval proceedings regarding multi-year rate plans and earnings sharing mechanisms, corporate finance matters such as the cost of capital and capitalization, valuation of energy and utility assets, merger impacts, revenue requirements, lead-lag studies/cash working capital, and regulatory policy.

Regulatory Advisory

- Provided financial modeling, development of expert reports, and preparation of multiple rounds of testimony on behalf of U.S. and Canadian investor-owned electric, natural gas, and water utilities related to multiple aspects of the ratemaking process, including: performance-based ratemaking; cost of capital; ring fencing; revenue requirements and lead-lag studies/cash working capital; decoupling; prudence and cost recovery; capital tracker tariff mechanisms; cost allocation and shared services; merger approval; securitization and ratemaking policy.
- Consulting assignments have included utility clients across the U.S. and Canada.

Financial Advisory Assignments

Competitive Solicitations & Asset Divestitures

- Sell-side support for approximately $2 billion in generating asset transactions, including nuclear, natural gas, and coal generating facilities.
- Buy-side due diligence support for U.S., Canadian, and international investors in electric and natural gas LDC utility operations, wind generation, natural gas pipeline facilities, and water/wastewater utilities.
- Regulatory policy, ring-fencing, and merger impacts advisory services including expert testimony, provided to U.S. and Canadian investor-owned utilities.

Valuation Services

- Developed Fairness Opinions issued by CE Capital Advisors, Inc. to Boards of Directors of companies entering into asset purchases and sales. Led valuation modeling on multiple energy-related valuation assignments using the Income Approach, Cost Approach, and Sales Comparison Approach.

Litigation Advisory Assignments

- Prepared economic and valuation analyses and expert reports in proceedings related to contract disputes, takings claims, and bankruptcy proceedings. Clients include international diversified energy companies, regulated utilities, and bondholders.

Management and Operations Consulting Assignments

- Performed prudence reviews, including contracting strategy reviews and assessments of project controls and oversight for developers of nuclear-generating capacity uprates and new nuclear facilities.
- Performed operations and financial performance benchmarking and studies of productivity programs.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2004 – Present)
President and Vice Chair

CE Capital Advisors, Inc. (2004 – 2023)
A FINRA-Member broker-dealer subsidiary of Concentric Energy Advisors, Inc.

Ernst & Young (2000 – 2001, 2003 – 2004)
Staff Auditor and Database Management Associate

ZIA Information Analysis Group (1997 – 2000)

EDUCATION

Boston College
M.B.A., 2003

Colgate University
B.A., Economics, 1996

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Certified Public Accountant, 2004
Massachusetts Society of Certified Public Accountants, 2004
American Institute of Certified Public Accountants, 2011

PRESENTATIONS

"Regulatory Treatment of Timing Differences Related to Pension and OPEB Costs." Presented to the Ontario Energy Board, July 2016 (Docket No. EB-2015-0040).
"Financial Management and Capital Markets." University of Idaho Utility Executive Course, 2018.
"Increasing Shareholder Value through the Capital Markets." University of Idaho Utility Executive Course, 2015, 2016 and 2017.
"A Comparative Analysis of Return on Equity of Natural Gas Utilities" (with Jim Coyne and Julie Lieberman), presented to the Ontario Energy Association, June 2007.

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arkansas Public Service Commission				
Liberty Utilities	02/23	The Empire District Electric Company	Docket 22-085-U	Return on Equity Capital Structure
Connecticut Public Utilities Regulatory Authority				
SJW Group and Connecticut Water Service, Inc.	12/18	Application of SJW Group and Connecticut Water Service, Inc. for Approval of Change of Control	Docket No. 18-07-10	Merger Impacts Cost of Debt and Credit Quality
SJW Group and Connecticut Water Service, Inc.	04/19	Application of SJW Group and Connecticut Water Service, Inc. for Approval of Change of Control	Docket No. 19-04-02	Merger Impacts Cost of Debt and Credit Quality
The United Illuminating Company	09/22	The United Illuminating Company	Docket No. 22-08-08	Multi-Year Rate Plan Revenue Requirements
The Southern Connecticut Gas Company and Connecticut Natural Gas Company	11/23	The Southern Connecticut Gas Company and Connecticut Natural Gas Company	Docket No. 23-11-02	Revenue Requirements
The United Illuminating Company	11/24	The United Illuminating Company	Docket No. 24-10-04	Revenue Requirements
Illinois Commerce Commission				
The Ameren Illinois Utilities	07/10	Central Illinois Light Company; Central Illinois Public Service Company; Illinois Power Company	Docket No.	Rate Base Adjustments Earnings Attrition

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Maine Public Utilities Commission				
The Maine Water Company	07/19	Application for Approval of Reorganization Pursuant to 35-A M.R.S. § 708	Docket No. 2019-00096	Merger Impacts, Customer Benefits, Public Interest
Unitil Corporation, Northern Utilities, Inc.	07/24	Request for Regulatory Approvals Related to a Merger of Bangor Natural Gas Company Into Unitil Corporation and Related Debt and Affiliate Arrangements (35-A M.R.S. §§ 707, 708, 901 & 902)	Docket No. 2024-00174	Utility valuation; Merger commitments; Rate base Valuation
Massachusetts Department of Public Utilities				
National Grid	11/17	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 17-170	Performance-Based Rate Plan Revenue Requirement
National Grid	04/18	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 17-170	Impact of the Tax Cuts and Jobs Act of 2017 Administrative and General Expense Allocations
The Berkshire Gas Company	05/18	The Berkshire Gas Company	D.P.U. 18-40	Revenue Requirement
National Grid	11/20	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 20-120	Performance-Based Rate Plan Revenue Requirement
National Grid	11/23	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 23-150	Performance-Based Rate Plan Revenue Requirement

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Missouri Public Service Commission				
Liberty Utilities (Empire District Electric Company)	11/24	Liberty Utilities (Empire District Electric Company)	Case No. ER-2024-0261	Return on Equity Cost of Debt Capital Structure
New Hampshire Public Utilities Commission				
Liberty Utilities (EnergyNorth Natural Gas) Corp.	04/17	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Docket No. DG 17-048	Temporary Rates
Liberty Utilities (EnergyNorth Natural Gas) Corp.	04/17	Liberty Utilities (EnergyNorth Natural Gas) Corp.	Docket No. DG 17-048	Revenue Requirement Step Adjustments
Liberty Utilities (Granite State Electric) Corp.	05/23	Liberty Utilities (Granite State Electric) Corp.	Docket No. DG 23-039	Temporary Rates
Liberty Utilities (Granite State Electric) Corp.	05/23	Liberty Utilities (Granite State Electric) Corp.	Docket No. DG 23-039	Multi-Year Rate Plan Revenue Requirement
Nova Scotia Utility Board				
Nova Scotia Power, Inc.	01/22	Nova Scotia Power, Inc.	M10431	Earnings Sharing Mechanism, Storm Rider, and Demand Side Management Rider
Oklahoma Corporate Commission				
Liberty Utilities Co.	02/22	Liberty-Empire	Cause No. PUD 202100163	Return on Equity Capital Structure
Liberty Utilities Co.	06/22	Liberty-Empire	Cause No. PUD 202100050	Winter Storm Funding and Cost Recovery
Ontario Energy Board				
Ontario Power Generation	05/16	Ontario Power Generation	EB 2016-0152	Cost of Capital: Equity Thickness

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Ontario Power Generation	12/20	Ontario Power Generation	EB 2020-0290	Cost of Capital: Equity Thickness
Hydro One Networks Inc.	08/21	Hydro One Networks Inc.	EB 2021-0110	Productivity Framework Review
Enbridge Gas Inc. (Operating as Enbridge Gas Distribution Inc.)	10/22	Enbridge Gas Inc. (Operating as Enbridge Gas Distribution Inc.)	EB-2022-0200	Cost of Capital: Equity Thickness
Ontario Energy Association, Coalition of Large Distributors and Ontario Power Generation	07/24	Generic proceeding commenced by the Ontario Energy Board to consider the cost of capital parameters and deemed capital structure to be used to set rates	EB-2024-0063	Cost of Capital (ROE, Cost of Debt, and Capital Structure); Carrying Costs on Regulatory Deferrals; Carrying Costs on Cloud Computing Deferrals

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Oregon Public Utilities Commission				
Northwest Natural Gas Company d/b/a NW Natural	05/25	Northwest Natural Gas Company d/b/a NW Natural	UG 520	Future Test Year; Rate Base Development
Rhode Island Division of Public Utilities and Carriers				
PPL Corporation	11/21	PPL Corporation and PPL Rhode Island Holdings, LLC	D-21-09	Merger Impacts
Rhode Island Public Utilities Commission				
The Narragansett Electric Company d/b/a Rhode Island Energy, a subsidiary of PPL Corporation	11/25	The Narragansett Electric Company d/b/a Rhode Island Energy	25-33-GE	Hold Harmless Commitment Corporate Finance Principles
Pennsylvania Public Utilities Commission				
PPL Electric Utilities Corporation	10/25	PPL Electric Utilities Corporation	R-2025-3057164	Future Test Year Revenue Requirement
South Dakota Public Utilities Commission				
Northern States Power Company-MN	06/11	Northern States Power Company-MN	EL 11-019	Return on Equity Capital Structure

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Vermont Public Utility Commission				
Vermont Department of Public Service	08/17	Joint Petition of NorthStar Decommissioning Holdings, LLC, NorthStar Nuclear Decommissioning Company, LLC, NorthStar Group Services, Inc., LVI Parent Corp., NorthStar Group Holdings, LLC, Entergy Nuclear Vermont Investment Company, LLC, and Entergy Nuclear Operations, Inc., to transfer ownership of Entergy Nuclear Vermont Yankee, LLC, and for certain ancillary approvals, pursuant to 30 V.S.A. §§ 107, 231, and 232	Docket No. 8880	Nuclear Facility Transfer Financial Capability and Credit Quality

LEAD-LAG AND CASH WORKING CAPITAL STUDIES

JURISDICTION	SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.
Regulatory Commission of Alaska	Golden Heart Utilities, Inc. and College Utilities Corporation	08/21	Golden Heart Utilities, Inc. and College Utilities Corporation	U-21-070 U-21-071
Regulatory Commission of Alaska	Golden Heart Utilities, Inc. and College Utilities Corporation	08/24	Golden Heart Utilities, Inc. and College Utilities Corporation	U-24-030 U-24-031
Connecticut Public Utilities Regulatory Authority	The United Illuminating Company	07/16	The United Illuminating Company	Docket No. 16-06-04
Connecticut Public Utilities Regulatory Authority	The Southern Connecticut Gas Company	06/17	The Southern Connecticut Gas Company	Docket No. 17-05-42
Connecticut Public Utilities Regulatory Authority	Connecticut Natural Gas Corporation	06/18	Connecticut Natural Gas Corporation	Docket No. 18-05-16
Kentucky Public Service Commission	Duke Energy Kentucky	06/25	Duke Energy Kentucky	2025-00125
Massachusetts Department of Public Utilities	National Grid	11/17	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 17-170
Massachusetts Department of Public Utilities	National Grid	11/20	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 20-120
Massachusetts Department of Public Utilities	National Grid	11/23	Boston Gas Company and Colonial Gas Company (each d/b/a National Grid)	D.P.U. 23-150
New Mexico Public Regulation Commission	El Paso Electric Company	05/20	El Paso Electric Company	Case No. 20-00104-UT

JURISDICTION	SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.
Public Utility Commission of Texas	El Paso Electric Company	02/17	El Paso Electric Company	Docket No. 46831
Public Utility Commission of Texas	El Paso Electric Company	06/21	El Paso Electric Company	Docket No. 52195
Railroad Commission of Texas	Atmos Pipeline – Texas (APT), a division of Atmos Energy Corporation	05/23	Atmos Pipeline – Texas (APT), a division of Atmos Energy Corporation	Case No. 00013758
Railroad Commission of Texas	Atmos Energy Corporation, West Texas Division	10/24	Atmos Energy Corporation, West Texas Division	Docket No. OS-24-00018879 (West Texas)

CREDIT METRICS ANALYSIS

@ 45%

Label	Item	Formula/Source	Units	2027	2028	2029	2030	2031
[a]	Rate Base (financed by capital structure)	Ex C1-01-01 (Tables 1-5)	$ Millions	$ 24,929.8	$ 26,015.4	$ 27,079.0	$ 28,338.6	$ 35,595.3
[b]	Return on Equity	Ex C1-01-01 (Tables 1-5)	%	9.11%	9.11%	9.11%	9.11%	9.11%
[c]	Equity Portion	Toggle	%	45%	45%	45%	45%	45%
[d]	Cost of Debt	Ex C1-01-01 (Tables 1-5)	%	4.60%	4.78%	4.90%	4.96%	4.98%
[e]	Total Debt	[a]*(1-[c])	$ Millions	$ 13,711.4	$ 14,308.5	$ 14,893.5	$ 15,586.2	$ 19,577.4
[f]	Income Tax Rate	Ex F4-02-01 (Table 3d)	%	25%	25%	25%	25%	25%
[g]	Net Income	[a]*[b]*[c]	$ Millions	$ 1,022.0	$ 1,066.5	$ 1,110.1	$ 1,161.7	$ 1,459.2
[h]	Interest Expense	[a]*(1-[b])*[d]	$ Millions	$ 630.7	$ 683.9	$ 729.8	$ 773.1	$ 975.0
[i]	Income Taxes	Ex F4-02-01 (Tables 3b & 3d)	$ Millions	$ 13.9	$ 53.0	$ 72.3	$ 88.1	$ 97.9
[j]	Depreciation	Ex F4-01-01 (Tables 1-2), Ex H01-02-01 (Tables 1-2)	$ Millions	$ 975.2	$ 1,033.4	$ 1,076.5	$ 1,111.2	$ 1,332.1
[k]	Cost of Lesser of UNL or ARC	Ex C2-01-01 (Tables 1-5)	$ Millions	$ 4.7	$ 1.1	$ -	$ -	$ -
[l]	EBITDA	[g]+[h]+[i]+[j]-[k]	$ Millions	$ 2,637.1	$ 2,835.7	$ 2,988.7	$ 3,134.1	$ 3,864.2
[m]	Funds from Operations	[l]-[h]-[i]	$ Millions	$ 1,992.5	$ 2,098.8	$ 2,186.6	$ 2,272.9	$ 2,791.3
[n]	Pension and OPEB Accrual	Ex F4-02-01 (Tables 3b & 3d)	$ Millions	$ 270.8	$ 270.4	$ 278.8	$ 284.6	$ 296.7
[o]	Pension Plan Contributions & OPEB Payments	Ex F4-02-01 (Tables 3b & 3d)	$ Millions	$ 261.0	$ 269.8	$ 285.4	$ 294.6	$ 305.3
[p]	Nuclear Waste Management Expenses	Ex F4-02-01 (Tables 3b & 3d)	$ Millions	$ 30.4	$ 47.2	$ 58.9	$ 72.9	$ 79.1
[q]	Receipts from Nuclear Segregated Funds	Ex F4-02-01 (Tables 3b & 3d)	$ Millions	$ 498.2	$ 420.1	$ 347.2	$ 326.7	$ 342.0
[r]	Cash Expenditures for Nuclear Waste & Decommissioning	Ex F4-02-01 (Tables 3b & 3d)	$ Millions	$ 637.4	$ 539.1	$ 437.9	$ 443.3	$ 472.1
[s]	Contributions to Nuclear Segregated Funds	Ex F4-02-01 (Tables 3b & 3d)	$ Millions	$ -	$ -	$ -	$ -	$ -
[t]	Cashflow from Operations	[l]-[h]-[i]+[n]-[o]+[p]+[q]-[r]-[s]	$ Millions	$ 1,893.5	$ 2,027.6	$ 2,148.2	$ 2,219.2	$ 2,731.7
[u]	OPEB Liabilities	Ex. F4-03-02 Attachment 1	$ Millions	$ 3,235.4	$ 3,361.9	$ 3,485.3	$ 3,618.7	$ 3,757.4
[v]	Pension Liabilities	Ex. F4-03-02 Attachment 1	$ Millions	$ 386.9	$ 348.9	$ 299.5	$ 251.1	$ 204.6
[w]	Pension Allocation	Ex. F4-03-02	%	86.8%	86.4%	86.9%	87.2%	87.2%
	METRICS - CALCULATED							
	FFO/Debt	[l] / {[e] + ([u] +[v]) x (1 -[f]) x[w]}		12.4%	12.6%	12.6%	12.5%	12.6%
	CFO/Debt	[t] / ([e] +[u] x[w])		13.5%	13.9%	14.2%	14.0%	13.8%

CREDIT METRICS ANALYSIS

Label	Item	@ 52% Formula/Source	Units	2027	2028	2029	2030	2031
[a]	Rate Base (financed by capital structure)	Ex C1-01-01 (Tables 1-5)	$ Millions	$ 24,929.8	$ 26,015.4	$ 27,079.0	$ 28,338.6	$ 35,595.3
[b]	Return on Equity	Ex C1-01-01 (Tables 1-5)	%	9.11%	9.11%	9.11%	9.11%	9.11%
[c]	Equity Portion	Toggle	%	52%	52%	52%	52%	52%
[d]	Cost of Debt	Ex C1-01-01 (Tables 1-5)	%	4.60%	4.78%	4.90%	4.96%	4.98%
[e]	Total Debt	[a]*(1-[c])	$ Millions	$ 11,966.3	$ 12,487.4	$ 12,997.9	$ 13,602.5	$ 17,085.7
[f]	Income Tax Rate	Ex F4-02-01 (Table 3d)	%	25%	25%	25%	25%	25%
[g]	Net Income	[a]*[b]*[c]	$ Millions	$ 1,181.0	$ 1,232.4	$ 1,282.8	$ 1,342.5	$ 1,686.2
[h]	Interest Expense	[a]*(1-[b])*[d]	$ Millions	$ 550.4	$ 596.9	$ 636.9	$ 674.7	$ 850.9
[i]	Income Taxes	Ex F4-02-01 (Tables 3b & 3d)	$ Millions	$ 13.9	$ 53.0	$ 72.3	$ 88.1	$ 97.9
[j]	Depreciation	Ex F4-01-01 (Tables 1-2), Ex H01-02-01 (Tables 1-2)	$ Millions	$ 975.2	$ 1,033.4	$ 1,076.5	$ 1,111.2	$ 1,332.1
[k]	Cost of Lesser of UNL or ARC	Ex C2-01-01 (Tables 1-5)	$ Millions	$ 4.7	$ 1.1	$ -	$ -	$ -
[l]	EBITDA	[g]+[h]+[i]+[j]-[k]	$ Millions	$ 2,715.8	$ 2,914.6	$ 3,068.5	$ 3,216.5	$ 3,967.1
[m]	Funds from Operations	[l]-[h]-[i]	$ Millions	$ 2,151.5	$ 2,264.7	$ 2,359.3	$ 2,453.7	$ 3,018.3
[n]	Pension and OPEB Accrual	Ex F4-02-01 (Tables 3b & 3d)	$ Millions	$ 270.8	$ 270.4	$ 278.8	$ 284.6	$ 296.7
[o]	Pension Plan Contributions & OPEB Payments	Ex F4-02-01 (Tables 3b & 3d)	$ Millions	$ 261.0	$ 269.8	$ 285.4	$ 294.6	$ 305.3
[p]	Nuclear Waste Management Expenses	Ex F4-02-01 (Tables 3b & 3d)	$ Millions	$ 30.4	$ 47.2	$ 58.9	$ 72.9	$ 79.1
[q]	Receipts from Nuclear Segregated Funds	Ex F4-02-01 (Tables 3b & 3d)	$ Millions	$ 498.2	$ 420.1	$ 347.2	$ 326.7	$ 342.0
[r]	Cash Expenditures for Nuclear Waste & Decommissioning	Ex F4-02-01 (Tables 3b & 3d)	$ Millions	$ 637.4	$ 539.1	$ 437.9	$ 443.3	$ 472.1
[s]	Contributions to Nuclear Segregated Funds	Ex F4-02-01 (Tables 3b & 3d)	$ Millions	$ -	$ -	$ -	$ -	$ -
[t]	Cashflow from Operations	[l]-[h]-[i]+[n]-[o]+[p]+[q]-[r]-[s]	$ Millions	$ 2,052.5	$ 2,193.5	$ 2,320.9	$ 2,400.0	$ 2,958.7
[u]	OPEB Liabilities	Ex. F4-03-02 Attachment 1	$ Millions	$ 3,235.4	$ 3,361.9	$ 3,485.3	$ 3,618.7	$ 3,757.4
[v]	Pension Liabilities	Ex. F4-03-02 Attachment 1	$ Millions	$ 386.9	$ 348.9	$ 299.5	$ 251.1	$ 204.6
[w]	Pension Allocation	Ex. F4-03-02	%	86.8%	86.4%	86.9%	87.2%	87.2%
	METRICS - CALCULATED							
	FFO/Debt	[l] / {[e] + ([u] +[v]) x (1 -[f]) x[w]}		15.0%	15.2%	15.3%	15.2%	15.3%
	CFO/Debt	[t] / ([e] +[v] x[w])		16.7%	17.2%	17.5%	17.4%	17.1%

Notes:

General	Amounts presented in this schedule are as of November 24, 2025. Amounts do not reflect OPG's rate shaping proposal or Clean Electricity Investment Tax Credits, which are considered in Canada's 2025 budget but have not yet been passed into law.
[h]	The Cost of Debt is based on OPG's forecasted Cost of Debt in its rates application, based on the assumptions therein. A decrease from OPG's proposed equity thickness of 52% would likely increase the Cost of Debt, although, conservatively, no such impact has been reflected in this analysis.
[k]	"Cost of Lesser of UNL or ARC" is subtracted to arrive at EBITDA. The return on the lesser of the Unfunded Nuclear Liability ("UNL") and the Asset Retirement Cost ("ARC") is different than the return applied to other elements of OPG's rate base.
[n] through [s]	These adjustments are made to adjust net income for cash and non-cash items to arrive at Cashflow from Operations.
[u] and [v]	S&P adjusts debt for the after-tax amount of OPEB Liabilities and Pension Liabilities. Moody's adjusts debt for the pre-tax amount of Pension Liabilities.
[w]	OPG's pension and OPEB liabilities are not segregated for ratemaking purposes. This allocation factor allocates a portion of OPG's pension and OPEB liabilities to the prescribed operations.

-- ALL COMPANY DATA --

Company	Ticker	[1] S&P/Moody's Credit Rating Of At Least BBB-/Baa3	[2] Generation Assets Included in Rate Base	[3] Regulated Generation Operating Capacity (MW)	[4] Regulated Hydro Generation Operating Capacity (MW)	[5] Regulated Nuclear Generation Operating Capacity (MW)	[6] Percent of Generation Assets that are Hydroelectric	[7] Percent of Generation Assets that are Nuclear	[8] Own Regulated Nuclear and/or Hydroelectric Generation	[9] % Regulated Operating Revenue of Total Revenue > 60%	[10 % Regulated Operating Income of Total Income > 60%	[11] % Regulated Electric Revenue of Total Regulated Revenue > 80%	[12] % Regulated Electric Income of Total Regulated Income > 80%
ALLETE, Inc.	ALE	BBB	Yes	1,679	125.70	-	7%	0%	Yes	76%	100%	98%	98%
Alliant Energy Corporation	LNT	BBB+	Yes	8,931	56.37	-	1%	0%	No	98%	98%	85%	85%
Ameren Corporation	AEE	BBB+	Yes	10,032	384.00	1,236.00	4%	12%	Yes	100%	100%	85%	84%
American Electric Power Company, Inc.	AEP	BBB+	Yes	24,288	627.00	2,278.00	3%	9%	Yes	98%	97%	100%	100%
Avista Corporation	AVA	BBB	Yes	2,143	1,155.50	-	54%	0%	Yes	100%	95%	68%	74%
Black Hills Corporation	BKH	BBB+	Yes	726	-	-	0%	0%	No	100%	100%	38%	48%
CenterPoint Energy, Inc.	CNP	BBB+	Yes	780	-	-	0%	0%	No	99%	100%	50%	60%
CMS Energy Corporation	CMS	BBB+	Yes	7,308	128.10	-	2%	0%	No	96%	100%	68%	63%
Consolidated Edison, Inc.	ED	A-	Yes	798	-	-	0%	0%	No	97%	86%	75%	71%
Dominion Resources, Inc.	D	BBB+	Yes	25,743	549.10	4,147.41	2%	16%	Yes	92%	94%	100%	100%
DTE Energy Company	DTE	BBB+	Yes	11,675	-	1,161.00	0%	10%	Yes	56%	88%	77%	74%
Duke Energy Corporation	DUK	BBB+	Yes	53,726	1,338.91	9,195.48	2%	17%	Yes	100%	100%	92%	90%
Edison International	EIX	BBB	Yes	3,572	938.52	632.47	26%	18%	Yes	100%	100%	100%	100%
Entergy Corporation	ETR	BBB+	Yes	26,239	72.50	4,027.50	0%	15%	Yes	99%	99%	98%	99%
Eversource Energy	ES	BBB+	No	62	-	-	0%	0%	No	100%	94%	82%	85%
Exelon Corporation	EXC	A-	No	-	-	-	0%	0%	No	100%	100%	91%	90%
FirstEnergy Corporation	FE	BBB	Yes	3,183	-	-	0%	0%	No	100%	100%	100%	100%
Evergy, Inc.	EVRG	BBB+	Yes	11,863	5.30	1,179.70	0%	10%	Yes	100%	100%	100%	100%
Hawaiian Electric Industries, Inc.	HE	B-	Yes	1,688	4.10	-	0%	0%	No	100%	94%	100%	100%
IDACORP, Inc.	IDA	BBB	Yes	3,923	1,937.30	-	49%	0%	Yes	100%	100%	100%	100%
MGE Energy, Inc.	MGEE	AA-	Yes	1,221	-	-	0%	0%	No	100%	79%	70%	79%
NextEra Energy, Inc.	NEE	A-	Yes	39,805	-	3,589.92	0%	9%	Yes	73%	85%	100%	100%
NorthWestern Corporation	NWE	BBB	Yes	1,528	470.70	-	31%	0%	Yes	100%	100%	76%	86%
OGE Energy Corporation	OGE	BBB+	Yes	7,284	-	-	0%	0%	No	100%	100%	100%	100%
Otter Tail Corporation	OTTR	BBB	Yes	1,229	4.14	-	0%	0%	No	39%	29%	100%	100%
PG&E Corporation	PCG	BB	Yes	7,657	2,544.06	2,240.00	33%	29%	Yes	100%	100%	71%	58%
Pinnacle West Capital Corporation	PNW	BBB+	Yes	6,371	-	1,164.87	0%	18%	Yes	100%	100%	100%	100%
TXNM Energy, Inc.	TXNM	BBB	Yes	1,606	-	302.59	0%	19%	Yes	100%	100%	100%	100%
Portland General Electric Company	POR	BBB+	Yes	3,792	435.36	-	11%	0%	Yes	100%	100%	100%	100%
PPL Corporation	PPL	A-	Yes	8,075	132.30	-	2%	0%	No	100%	100%	94%	94%
Public Service Enterprise Group Inc.	PEG	BBB+	Yes	87	-	-	0%	0%	No	78%	84%	72%	78%
Sempra Energy	SRE	BBB+	Yes	1,690	-	-	0%	0%	No	88%	81%	54%	51%
Southern Company	SO	A-	Yes	33,461	2,410.82	4,742.47	7%	14%	Yes	91%	96%	80%	85%
Unitil Corporation	UTL	BBB+	No	1	-	-	0%	0%	No	100%	100%	53%	34%
Wisconsin Energy Corporation	WEC	A-	Yes	9,321	169.50	-	2%	0%	No	98%	98%	56%	57%
Xcel Energy Inc.	XEL	BBB+	Yes	21,835	219.20	1,738.00	1%	8%	Yes	99%	100%	81%	85%
Algonquin Power & Utilities Corporation	AQN	BBB	n/a	1,300	16.00	-	1%	0%	No	98%	99%	56%	54%
AltaGas Limited	ALA	BBB-	n/a	10	-	-	0%	0%	No	36%	54%	0%	0%
Canadian Utilities Limited	CU	NR	No	-	-	-	0%	0%	No	85%	87%	51%	57%
Emera Inc.	EMA	BBB	Yes	8,037	-	-	0%	0%	No	97%	95%	76%	79%
Enbridge Inc.	ENB	BBB+	No	26	-	-	0%	0%	No	95%	98%	0%	0%
Fortis Inc.	FTS	A-	Yes	3,536	22.40	-	1%	0%	No	99%	99%	83%	85%
Hydro One Limited	H	A	n/a	-	-	-	0%	0%	No	99%	100%	100%	100%
TC Energy Corporation	TRP	BBB+	No	-	-	-	0%	0%	No	82%	73%	0%	0%

Notes:
[1] Source: Bloomberg Professional, as of May 31, 2025
[2] - [5] Source: S&P Capital IQ
[6] Equals [4] / [3]
[7] Equals [5] / [3]
[8] Equals "Yes" if ([6] + [7]) > 5%
[9] - [12] Source: Form 10-Ks for 2022, 2023, & 2024 (three-year average) for US companies; Annual Reports for Canadian companies
[13] Equals "Yes" if Screens [1] - [8] are passed. Manual inclusions are: AQN, EMA, and FTS, as explained in Concentric's report, and SO, due to close proximity of only failing screen (regulated electric revenue as a percentage of total regulated revenue).
[14] Equals "Yes" if [13] equals "Yes" and [6] > 5%
[15] Equals "Yes" if [13] equals "Yes" and [7] > 5%

	---- MAIN PROXY GROUP SCREENING ----								HYDRO SCREENING		NUCLEAR SCREENING	
				60%	60%	80%	80%	[13]	5%	[14]	5%	[15]
Company	S&P/Moody's Credit Rating Of At Least BBB-/Baa3	Generation Assets Included in Rate Base	Own Regulated Nuclear and/or Hydroelectric Generation	% Regulated Operating Revenue of Total Revenue > 60%	% Regulated Operating Income of Total Income > 60%	% Regulated Electric Revenue of Total Regulated Revenue > 80%	% Regulated Electric Income of Total Regulated Income > 80%	Passes Main Screens?	% Hydroelectric	Passes Hydro Screen?	% Nuclear	Passes Nuclear Screen?
ALLETE, Inc.	1	1	1	1	1	1	1	Yes	7%	Yes	0%	No
Alliant Energy Corporation	1	1	0	1	1	1	1	No	1%	No	0%	No
Ameren Corporation	1	1	1	1	1	1	1	Yes	4%	No	12%	Yes
American Electric Power Company, Inc.	1	1	1	1	1	1	1	Yes	3%	No	9%	Yes
Avista Corporation	1	1	1	1	1	0	0	No	54%	No	0%	No
Black Hills Corporation	1	1	0	1	1	0	0	No	0%	No	0%	No
CenterPoint Energy, Inc.	1	1	0	1	1	0	0	No	0%	No	0%	No
CMS Energy Corporation	1	1	0	1	1	0	0	No	2%	No	0%	No
Consolidated Edison, Inc.	1	1	0	1	1	0	0	No	0%	No	0%	No
Dominion Resources, Inc.	1	1	1	1	1	1	1	Yes	2%	No	16%	Yes
DTE Energy Company	1	1	1	0	1	0	0	No	0%	No	10%	No
Duke Energy Corporation	1	1	1	1	1	1	1	Yes	2%	No	17%	Yes
Edison International	1	1	1	1	1	1	1	Yes	26%	Yes	18%	Yes
Entergy Corporation	1	1	1	1	1	1	1	Yes	0%	No	15%	Yes
Eversource Energy	1	0	0	1	1	1	1	No	0%	No	0%	No
Exelon Corporation	1	0	0	1	1	1	1	No	0%	No	0%	No
FirstEnergy Corporation	1	1	0	1	1	1	1	No	0%	No	0%	No
Evergy, Inc.	1	1	1	1	1	1	1	Yes	0%	No	10%	Yes
Hawaiian Electric Industries, Inc.	0	1	0	1	1	1	1	No	0%	No	0%	No
IDACORP, Inc.	1	1	1	1	1	1	1	Yes	49%	Yes	0%	No
MGE Energy, Inc.	1	1	0	1	1	0	0	No	0%	No	0%	No
NextEra Energy, Inc.	1	1	1	1	1	1	1	Yes	0%	No	9%	Yes
NorthWestern Corporation	1	1	1	1	1	0	1	No	31%	No	0%	No
OGE Energy Corporation	1	1	0	1	1	1	1	No	0%	No	0%	No
Otter Tail Corporation	1	1	0	0	0	1	1	No	0%	No	0%	No
PG&E Corporation	0	1	1	1	1	0	0	No	33%	No	29%	No
Pinnacle West Capital Corporation	1	1	1	1	1	1	1	Yes	0%	No	18%	Yes
TXNM Energy, Inc.	1	1	1	1	1	1	1	Yes	0%	No	19%	Yes
Portland General Electric Company	1	1	1	1	1	1	1	Yes	11%	Yes	0%	No
PPL Corporation	1	1	0	1	1	1	1	No	2%	No	0%	No
Public Service Enterprise Group Inc.	1	1	0	1	1	0	0	No	0%	No	0%	No
Sempra Energy	1	1	0	1	1	0	0	No	0%	No	0%	No
Southern Company	1	1	1	1	1	1	1	Yes	7%	Yes	14%	Yes
Unitil Corporation	1	0	0	1	1	0	0	No	0%	No	0%	No
Wisconsin Energy Corporation	1	1	0	1	1	0	0	No	2%	No	0%	No
Xcel Energy Inc.	1	1	1	1	1	1	1	Yes	1%	No	8%	Yes
Algonquin Power & Utilities Corporation	1	0	0	1	1	0	0	Yes	1%	No	0%	No
AltaGas Limited	1	0	0	0	0	0	0	No	0%	No	0%	No
Canadian Utilities Limited	0	0	0	1	1	0	0	No	0%	No	0%	No
Emera Inc.	1	1	0	1	1	0	1	Yes	0%	No	0%	No
Enbridge Inc.	1	0	0	1	1	0	0	No	0%	No	0%	No
Fortis Inc.	1	1	0	1	1	1	1	Yes	1%	No	0%	No
Hydro One Limited	1	0	0	1	1	1	1	No	0%	No	0%	No
TC Energy Corporation	1	0	0	1	1	0	0	No	0%	No	0%	No
								18		5		12

MAIN PROXY 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

HYDRO PROXY GROUP

Company	Ticker
ALLETE, Inc.	ALE
Edison International	EIX
IDACORP, Inc.	IDA
Portland General Electric Company	POR
Southern Company	SO

NUCLEAR PROXY 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

ACTUAL EQUITY RATIO ANALYSIS

		Common Equity Ratio (%)					Common Equity Ratio (%)		
Proxy Group Company	**Ticker**	**2024**	**2023**	**2022**	**2021**	**2020**	**2020-2024 Average**	*Group*	*Group*
ALLETE, Inc.	ALE	62.07%	62.55%	59.71%	56.08%	58.12%	59.70%		*Hydro*
Ameren Corporation	AEE	53.73%	54.17%	53.91%	54.00%	53.44%	53.85%	*Nuclear*	
American Electric Power Company, Inc.	AEP	48.58%	48.45%	48.56%	47.76%	48.15%	48.30%	*Nuclear*	
Dominion Resources, Inc.	D	53.40%	55.08%	52.25%	53.04%	53.16%	53.39%	*Nuclear*	
Duke Energy Corporation	DUK	53.08%	52.87%	53.04%	53.39%	52.95%	53.07%	*Nuclear*	
Edison International	EIX	43.27%	44.77%	44.82%	48.09%	51.85%	46.56%	*Nuclear*	*Hydro*
Entergy Corporation	ETR	51.34%	52.01%	47.70%	45.54%	46.38%	48.59%	*Nuclear*	
Evergy, Inc.	EVRG	59.43%	58.84%	60.20%	60.04%	58.66%	59.43%	*Nuclear*	
IDACORP, Inc.	IDA	49.95%	49.42%	54.37%	55.00%	53.96%	52.54%		*Hydro*
NextEra Energy, Inc.	NEE	59.98%	58.67%	63.14%	62.12%	60.04%	60.79%	*Nuclear*	
Pinnacle West Capital Corporation	PNW	52.22%	49.56%	50.25%	51.12%	51.35%	50.90%	*Nuclear*	
TXNM Energy, Inc.	TXNM	50.23%	50.02%	49.41%	50.85%	50.73%	50.25%	*Nuclear*	
Portland General Electric Company	POR	45.57%	45.37%	43.24%	45.09%	46.07%	45.07%		*Hydro*
Southern Company	SO	55.54%	54.82%	54.58%	54.62%	54.92%	54.90%	*Nuclear*	*Hydro*
Xcel Energy Inc.	XEL	54.31%	54.58%	54.93%	54.52%	54.88%	54.64%	*Nuclear*	
Algonquin Power & Utilities Corporation	AQN	63.79%	65.91%	63.72%	61.24%	66.80%	64.29%		
Emera Inc.	EMA	50.50%	46.46%	46.82%	48.13%	46.94%	47.77%		
Fortis Inc.	FTS	50.87%	49.88%	48.77%	48.98%	48.48%	49.40%		
MEAN		53.21%	52.97%	52.75%	52.76%	53.16%	**52.97%**		
MEDIAN		52.65%	52.44%	52.64%	53.21%	53.06%	**52.80%**		
LOW		43.27%	44.77%	43.24%	45.09%	46.07%	45.07%		
HIGH		63.79%	65.91%	63.72%	62.12%	66.80%	64.29%		
Average Nuclear		52.93%	52.82%	52.73%	52.92%	53.04%	52.89%		
Median Nuclear		53.24%	53.52%	52.64%	53.21%	53.06%	53.23%		
Min Nuclear		43.27%	44.77%	44.82%	45.54%	46.38%	46.56%		
Max Nuclear		59.98%	58.84%	63.14%	62.12%	60.04%	60.79%		
Average Hydro		51.28%	51.38%	51.34%	51.78%	52.98%	51.75%		
Median Hydro		49.95%	49.42%	54.37%	54.62%	53.96%	52.54%		
Min Hydro		43.27%	44.77%	43.24%	45.09%	46.07%	45.07%		
Max Hydro		62.07%	62.55%	59.71%	56.08%	58.12%	59.70%		

AUTHORIZED EQUITY RATIO ANALYSIS - OPERATING SUBSIDIARIES

Company Name	State	Ticker	Service Type	Current	*Group*	*Group*	*S&P Credit Supportiveness*
Minnesota Power Enterprises, Inc.	Minnesota	ALE	Electric	53.00%		*Hydro*	*Highly Credit Supportive*
Ameren Illinois Company	Illinois	AEE	Electric	50.00%			*Very Credit Supportive*
Union Electric Company	Missouri	AEE	Electric	n/a	*Nuclear*	*Hydro*	*Very Credit Supportive*
AEP Texas, Inc.	Texas	AEP	Electric	42.50%			*Very Credit Supportive*
Appalachian Power Company	Virginia	AEP	Electric	48.24%		*Hydro*	*Highly Credit Supportive*
Appalachian Power Company	West Virginia	AEP	Electric	n/a		*Hydro*	*Very Credit Supportive*
Indiana Michigan Power Company	Indiana	AEP	Electric	n/a	*Nuclear*		*Highly Credit Supportive*
Indiana Michigan Power Company	Michigan	AEP	Electric	n/a	*Nuclear*		*Most Credit Supportive*
Kentucky Power Company	Kentucky	AEP	Electric	41.25%			*Most Credit Supportive*
Kingsport Power Company	Tennessee	AEP	Electric	48.90%			*Highly Credit Supportive*
Ohio Power Company	Ohio	AEP	Electric	54.43%			*Very Credit Supportive*
Public Service Company of Oklahoma	Oklahoma	AEP	Electric	51.12%			*Very Credit Supportive*
Southwestern Electric Power Company	Louisiana	AEP	Electric	n/a			*Highly Credit Supportive*
Southwestern Electric Power Company	Arkansas	AEP	Electric	n/a			*Highly Credit Supportive*
Southwestern Electric Power Company	Texas	AEP	Electric	49.37%			*Very Credit Supportive*
Wheeling Power Company	West Virginia	AEP	Electric	n/a			*Very Credit Supportive*
Virginia Electric and Power Company	North Carolina	D	Electric	52.50%	*Nuclear*		*Highly Credit Supportive*
Dominion Energy South Carolina	South Carolina	D	Electric	52.51%	*Nuclear*		*More Credit Supportive*
Duke Energy Carolinas, LLC	North Carolina	DUK	Electric	53.00%	*Nuclear*	*Hydro*	*Highly Credit Supportive*
Duke Energy Carolinas, LLC	South Carolina	DUK	Electric	51.21%	*Nuclear*	*Hydro*	*More Credit Supportive*
Duke Energy Florida, LLC	Florida	DUK	Electric	n/a			*Most Credit Supportive*
Duke Energy Indiana, LLC	Indiana	DUK	Electric	n/a			*Highly Credit Supportive*
Duke Energy Kentucky, Inc.	Kentucky	DUK	Electric	52.15%			*Most Credit Supportive*
Duke Energy Ohio, Inc.	Ohio	DUK	Electric	50.50%			*Very Credit Supportive*
Duke Energy Progress, LLC	North Carolina	DUK	Electric	53.00%	*Nuclear*		*Highly Credit Supportive*
Duke Energy Progress, LLC	South Carolina	DUK	Electric	52.43%	*Nuclear*		*More Credit Supportive*
Southern California Edison Company	California	EIX	Electric	n/a	*Nuclear*	*Hydro*	*More Credit Supportive*
Entergy Arkansas, Inc.	Arkansas	ETR	Electric	n/a	*Nuclear*		*Highly Credit Supportive*
Entergy Louisiana, LLC	Louisiana	ETR	Electric	n/a	*Nuclear*		*Highly Credit Supportive*
Entergy Mississippi, Inc.	Mississippi	ETR	Electric	n/a			*Highly Credit Supportive*
Entergy New Orleans, LLC	Louisiana	ETR	Electric	50.00%			*More Credit Supportive*
Entergy Texas, Inc.	Texas	ETR	Electric	51.21%			*Very Credit Supportive*
Evergy Metro	Kansas	EVRG	Electric	n/a	*Nuclear*		*Highly Credit Supportive*
Evergy Metro	Missouri	EVRG	Electric	n/a	*Nuclear*		*Very Credit Supportive*
Evergy Kansas South	Kansas	EVRG	Electric	50.13%	*Nuclear*		*Highly Credit Supportive*
Evergy Missouri West, Inc.	Missouri	EVRG	Electric	n/a			*Very Credit Supportive*
Westar Energy (KPL)	Kansas	EVRG	Electric	n/a			*Highly Credit Supportive*
Idaho Power Co.	Idaho	IDA	Electric	n/a		*Hydro*	*Very Credit Supportive*
Idaho Power Co.	Oregon	IDA	Electric	50.00%		*Hydro*	*More Credit Supportive*
Florida Power & Light Company	Florida	NEE	Electric	59.60%	*Nuclear*		*Most Credit Supportive*
Arizona Public Service Company	Arizona	PNW	Electric	51.93%	*Nuclear*		*More Credit Supportive*
Public Service Company of New Mexico	New Mexico	TXNM	Electric	51.00%	*Nuclear*		*Credit Supportive*
Texas-New Mexico Power Company	Texas	TXNM	Electric	45.00%			*Very Credit Supportive*
Portland General Electric Company	Oregon	POR	Electric	50.00%		*Hydro*	*More Credit Supportive*

Alabama Power Company	Alabama	SO	Electric	n/a	*Nuclear*	*Hydro*	*Most Credit Supportive*
Georgia Power Company	Georgia	SO	Electric	56.00%	*Nuclear*		*Highly Credit Supportive*
Mississippi Power Company	Mississippi	SO	Electric	53.00%			*Highly Credit Supportive*
Northern States Power Company	Minnesota	XEL	Electric	52.50%	*Nuclear*		*Highly Credit Supportive*
Northern States Power Company	North Dakota	XEL	Electric	52.50%	*Nuclear*		*Highly Credit Supportive*
Northern States Power Company	Wisconsin	XEL	Electric	52.50%	*Nuclear*		*Most Credit Supportive*
Northern States Power Company	South Dakota	XEL	Electric	n/a	*Nuclear*		*Very Credit Supportive*
Public Service Company of Colorado	Colorado	XEL	Electric	55.69%			*Very Credit Supportive*
Southwestern Public Service Company	Texas	XEL	Electric	n/a			*Very Credit Supportive*
Southwestern Public Service Company	New Mexico	XEL	Electric	54.70%			*Credit Supportive*
Liberty Utilities (CalPeco Electric) LLC	California	AQN	Electric	52.50%			*More Credit Supportive*
Liberty Utilities (Granite State Electric) Corp.	New Hampshire	AQN	Electric	52.00%			*Highly Credit Supportive*
The Empire District Electric Company	Arkansas	AQN	Electric	n/a			*Highly Credit Supportive*
The Empire District Electric Company	Oklahoma	AQN	Electric	n/a			*Very Credit Supportive*
The Empire District Electric Company	Missouri	AQN	Electric	n/a			*Very Credit Supportive*
The Empire District Electric Company	Kansas	AQN	Electric	n/a			*Highly Credit Supportive*
Tampa Electric Company	Florida	EMA	Electric	n/a			*Most Credit Supportive*
Nova Scotia Power	Nova Scotia	EMA	Electric	40.00%			*Credit Supportive*
Central Hudson Gas & Electric Corp.	New York	FTS	Electric	48.00%		*Hydro*	*Very Credit Supportive*
Tucson Electric Power Company	Arizona	FTS	Electric	54.32%			*More Credit Supportive*
UNS Electric, Inc.	Arizona	FTS	Electric	53.72%			*More Credit Supportive*
FortisAlberta	Alberta	FTS	Electric	37.00%			*Highly Credit Supportive*
FortisBC Inc.	British Columbia	FTS	Electric	41.00%			*Most Credit Supportive*
Newfoundland Power	Newfoundland and Labrador	FTS	Electric	45.00%			*Highly Credit Supportive*
Maritime Electric	Prince Edward Island	FTS	Electric	40.00%			*Credit Supportive*
		Average		**50.13%**			
		Median		**51.21%**			
		Min		37.00%			
		Max		59.60%			
		Average Nuclear		**52.92%**			
		Median Nuclear		**52.50%**			
		Min Nuclear		50.13%			
		Max Nuclear		59.60%			
		Average Hydro		**50.49%**			
		Median Hydro		**50.00%**			
		Min Hydro		48.00%			
		Max Hydro		53.00%			
		Average Most Cred. Supp.		49.30%			
		Median Most Cred. Supp.		52.15%			
		Min Most Cred. Supp.		41.00%			
		Max Most Cred. Supp.		59.60%			

Notes:

Source: S&P Capital IQ, RRA rate case database, as of May 28, 2025, and internal Concentric research.

Note that only electric operating subsidiaries were included in this analysis. U.S. states that account for zero-cost of capital items in utilities' regulated capital structure (Florida, Arkansas, Indiana, and Michigan) were excluded from this analysis.

Florida Power & Light's authorized equity ratio was included based on an analysis of the capital structure excluding zero cost of capital effects.

Operating subsidaries were included in the Nuclear and Hydro groups based off of operating subsidiary-level owned generation data, rather than holding company-level, to better reflect operating subsidiary characteristics.

AUTHORIZED EQUITY RATIOS ANALYSIS - HOLDING COMPANY AVERAGES

HoldCo Name	Ticker	Average Authorized Equity Ratio of Operating Subsidiaries
ALLETE, Inc.	ALE	53.00%
Ameren Corporation	AEE	50.00%
American Electric Power Company, Inc.	AEP	47.97%
Dominion Resources, Inc.	D	52.51%
Duke Energy Corporation	DUK	52.05%
Edison International	EIX	n/a
Entergy Corporation	ETR	50.61%
Evergy, Inc.	EVRG	50.13%
IDACORP, Inc.	IDA	50.00%
NextEra Energy, Inc.	NEE	59.60%
Pinnacle West Capital Corporation	PNW	51.93%
TXNM Energy, Inc.	TXNM	48.00%
Portland General Electric Company	POR	50.00%
Southern Company	SO	54.50%
Xcel Energy Inc.	XEL	53.58%
Algonquin Power & Utilities Corporation	AQN	52.25%
Emera Inc.	EMA	40.00%
Fortis Inc.	FTS	45.58%
MEAN		**50.69%**
MEDIAN		**50.61%**

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Jonathan Myers
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P. 416.865.7532

BY EMAIL

CONFIDENTIAL — PRIVILEGED

February 14, 2025

Concentric Energy Advisors, Inc.
293 Boston Post Road West, Ste 500
Marlborough, MA 01752

Attention: Mr. Daniel Dane

Re: Retainer Letter Agreement – Ontario Power Generation – Cost of Capital

Dear Mr. Dane:

Torys LLP ("Torys" or "we") represents Ontario Power Generation ("OPG") in connection with its planned application to the Ontario Energy Board (the "Board") for payment amounts in respect of its prescribed electricity generation facilities for a period starting in 2027 (the "Application").

We confirm that, on behalf of and to assist us in providing legal advice to OPG in connection with the Application, Torys has agreed to retain Concentric Energy Advisors, Inc. (the "Consultant" or "you"), effective as of the date first written above (the "Effective Date"), to provide consulting services as described in this letter. By signing back a copy of this letter, the Consultant agrees that this letter contains the agreed-upon terms and conditions of its retainer with Torys effective on the Effective Date, subject to amendment by written agreement between the parties (the "Retainer Agreement").

1. No Conflict

The Consultant does not have any conflict of interest or other constraints on its ability to provide expert advice in connection with this Retainer Agreement. You confirm that you are free to provide your services to Torys in connection with Torys' representation of OPG in the Application. You agree that during this engagement you will not provide, directly or indirectly, any services to any other party in connection with the matters at issue in the Application.

2. Consultant Expertise

The Consultant has been selected to provide consulting services to Torys in connection with the Application as further described in Section 3 below. The sponsors of the work of the Consultant and the persons who have the relevant expertise will be:

- Daniel Dane — President

- John Trogonoski — Assistant Vice President
- James Coyne — Senior Vice President

(collectively referred to as the "Sponsors").

3. **Scope of Services and Work Product**

The Consultant will:

(a) assess the reasonableness of OPG's current Board-authorized cost of capital in anticipation of the Application (the "Study"). As part of the Study, the Consultant will:

(i) assess whether the cost of capital approved by the Board in the EB-2020-0290 proceeding (or, as modified in EB-2024-0063) is an appropriate basis for setting OPG's regulated nuclear and hydroelectric payment amounts;

(ii) assess changes in OPG's business and financial risk since EB-2020-0152 and prospectively;

(iii) perform a Fair Return Standard ("FRS") analysis, including in accordance with the (i) comparable investment standard; (ii) financial integrity standard; and (iii) capital attraction standard; that will include

(A) building on the OEB's findings in EB-2007-0905, EB-2010-0008, EB-2013-0321, EB- 2016-0152, EB-2020-0290, and, as appropriate, EB-2024-0063 with respect to OPG's cost of capital;

(B) selecting an appropriate peer group or groups against which OPG should be compared, including establishing the appropriate selection criteria for inclusion in the peer group(s). In addition, the Consultant will consider other market indicators of risks and return requirements for pure-play generation companies;

(C) analyzing the cost of capital of the peer group(s), as well as market and economic data and other factors that affect OPG's cost of capital;

(D) considering and making a recommendation regarding the risk premium applicable to OPG's return on equity; and

(E) considering such other factors that may affect OPG's cost of capital.

(b) 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;

(c) if requested by Torys, produce a written report(s) detailing the Study's methodology, analysis performed and the Consultant's findings and conclusions (the "Report"), which (i) shall be delivered to Torys no later than: June 30, 2025 for the draft Report and August 15, 2025 for the final Report, unless otherwise agreed to by the parties and (ii) may be filed by Torys with the Board in connection with the Application; and

(d) if requested by Torys, provide support during the hearing of the Application in connection with the scope of the services provided hereunder ("Application Support Services" and, together with the Study, the Discussion of Findings and the Report, the "Services"), which may include:

(i) assistance in responding to interrogatories applicable to the Report;

(ii) appearance at a technical conference to respond to oral questions on the Report;

(iii) testifying about the Report as an expert witness either orally or in writing; and

(iv) assisting in responding to undertakings (i.e., written questions during a hearing) on the Report.

4. **Fees and Invoices**

By entering into this Retainer Agreement, the Consultant acknowledges that:

(a) the price for the Consultant to perform the Study and participate in the Discussion of Findings shall be determined based on the hourly rates set forth in paragraph (b) below and shall in no event exceed [redacted] (net of HST), and together with delivery of the Report(s) (if requested by Torys) shall in no event exceed a total of [redacted] (not including HST) without prior written approval from Torys; and

(b) the price for the Consultant to provide Application Support Services (if requested by Torys will be charged based on following hourly rates:

Title	Hourly Rate (USD)
Chairman of the Board	[redacted]
Chief Executive Officer / President	[redacted]
Senior Vice President	[redacted]
Vice President	[redacted]
Assistant Vice President	[redacted]
Senior Project Manager	[redacted]

Project Manager	[redacted]
Senior Consultant	[redacted]
Consultant	[redacted]
Senior Analyst	[redacted]
Analyst	[redacted]
Associate	[redacted]
Project Assistant	[redacted]

All amounts stated herein are in US dollars unless otherwise specified herein.

Any disbursements for additional incidentals incurred by the Consultant in relation to this Retainer Agreement must be pre-approved by Torys or OPG in writing and shall be in accordance with Schedule 'A' (OPG's Business Expense Standards). In the event of conflict between any provisions of Schedule 'A' and any policies or fee schedules of the Consultant relating to the charging of travel expenses or other incidentals, the relevant provisions of Schedule 'A' shall prevail. Torys reserves the right to deduct any applicable non-resident withholding taxes from any amounts owing to the Consultant under this Retainer Agreement and remit such amounts to the applicable taxation authority.

The Consultant will submit monthly invoices reflecting actual work performed and expenses incurred. The Consultant shall direct all invoices relating to Services performed by it under this Retainer Agreement to Torys, to the attention of:

Mr. Jonathan Myers
Torys LLP
79 Wellington St. W., 30th Floor
Box 270, TD South Tower
Toronto, Ontario M5K 1N2
jmyers@torys.com

with copies to OPG, to the attention of:

Mr. Peter Cuff
Assistant General Counsel, Law Division
Ontario Power Generation
700 University Avenue, H18 E27
Toronto, ON M5G 1X6
peter.cuff@opg.com

Herman Mo
Senior Manager Regulatory Affairs

Ontario Power Generation
700 University Avenue, H18 E27
Toronto, ON M5G 1X6
herman.mo@opg.com

Invoices shall include at least the following information:

(a) identification of the billing period to which the account relates;

(b) an itemized summary of the services that have been undertaken by you, including a brief description thereof, the date on which the services were rendered, the time spent on the services, the individual who performed the services, and the billing rate of such individual; and

(c) an itemized and brief description of all expenses incurred during the billing period, with copies of supporting invoices.

Torys will send your invoice to OPG for its approval and if OPG does not approve your invoice, Torys will send it back to you for revision. Once OPG approves the invoice, Torys will submit the invoice to OPG's payment system. OPG pays invoices once per month (on the 25th of each month) and, for payment to be made on the 25th of a particular month, the invoice must have been approved in OPG's payment system by the 25th of the prior month. Once Torys receives the payment from OPG, Torys will send payment to you.

5. **Confidentiality**

All work performed by the Consultant in connection with this Retainer Agreement, including all findings, opinions and conclusions the Consultant reaches in relation to this Retainer Agreement, and any communications relating thereto, are strictly privileged and confidential and shall not be disclosed to any other person or party without the prior written consent of Torys or OPG. The Consultant agrees to designate all written communications and material accordingly. The Consultant further agrees to promptly notify Torys in the event that the Consultant receives a request to disclose information relating to this matter, and agrees to cooperate with Torys, to the fullest extent permitted by law, to prevent or limit the disclosure of such material or otherwise preserve the privileged and confidential status of such material.

The Consultant agrees to hold in confidence: (a) all information provided to the Consultant, and (b) the Consultant's opinions to Torys and to OPG as they relate to the information, whether the information or opinions are documentary or oral (collectively, the "Confidential Information"). The Consultant will not disclose the Confidential Information to any person unless Torys or OPG authorizes you in writing to do so. All documents given to the Consultant in connection with this Retainer Agreement remain the property of Torys or of OPG, and are held in trust by the Consultant as agent. The Consultant agrees to return these documents on request.

The Consultant will not refer to Torys or to OPG, directly or indirectly, in connection with the promotion of its services, without obtaining the prior written consent of Torys or OPG, as the case may be. Notwithstanding the foregoing, the Consultant may refer to the following information in materials used to promote its services: (i) the Board's file number for the Application, (ii) a general description of the nature and scope of the services provided, and (iii) the time period of the Retainer Agreement; provided that (a) Consultant has provided testimony before the Board in connection with this Retainer Agreement and (b) such information shall in no way include, reflect or reveal, directly or indirectly, any Confidential Information nor any information that is not available on the public record in the Application.

6. **Intellectual Property**

Nothing in this Retainer Agreement shall be deemed to transfer, license, assign, permit the use of, or otherwise convey an interest in whole or in part to the Consultant of any intellectual property belonging to OPG or any of its representatives or any third party whose intellectual property is in OPG's custody or control, and the use by the Consultant of any such intellectual property shall be subject to the prior written approval of OPG.

Torys and OPG shall at all times have full rights and title to all works prepared, generated or created by the Consultant pursuant to this Retainer Agreement, including, without limitation, any reports, presentations, status updates, or other documents created by the Consultant, and any related works, modifications or additions thereto (the "Work Product"), and may at all times take possession of or use any completed or partially completed Work Product, notwithstanding any provision, express or implied, to the contrary. Without limiting the generality of the foregoing, OPG shall own all intellectual property rights in all Work Product, and the Consultant hereby waives and assigns to OPG any such rights, and agrees to give OPG and its representatives all assistance as may be reasonably required to perfect such rights including, without limitation, obtaining waiver of moral rights from any of the Consultant's employees, partners or other representatives. Notwithstanding the foregoing, the Consultant shall retain sole and exclusive ownership of any pre-existing Consultant tools, methodologies, proprietary research and data, and modifications to the same, together with all intellectual property rights therein (the "Consultant Property"). Consultant grants to Torys and OPG a fully paid up, irrevocable, perpetual, non-exclusive, royalty-free license to use the Consultant Property contained within the Work Product for the purposes intended in this Retainer Agreement.

Notwithstanding anything contained in this Retainer Agreement to the contrary, nothing in this Retainer Agreement shall prevent the Consultant from utilizing any general know-how, ideas, techniques, concepts, methods, processes, or other knowledge applied, developed or created in performing the Services, on behalf of itself or its future customers. Consultant may (i) perform the same or similar services for others, and (ii) retain one copy of deliverables produced in connection with the Services hereunder for the sole purpose of documenting the conduct of its work and its exercise of due professional care in connection with the Services, provided that any of OPG's or Torys' Confidential Information is treated in accordance with the confidentiality requirements of this Retainer Agreement.

7. **Intellectual Property Protection**

The Consultant expressly warrants that the delivery, sale or use of the Consultant's Services will not infringe any Canadian or foreign patents, trademarks, copyrights, industrial design or other intellectual property rights and the Consultant shall indemnify and save Torys and OPG harmless from all claims, judgments and decrees that may be entered against Torys, OPG or their representatives against all damages, liability, costs and expenses (including legal fees and other attendant costs and expenses) Torys or OPG incurs by reason of any infringement or claim thereof.

8. **Controlled Nuclear Information**

The Consultant has been made aware of certain Canadian federal requirements relating to the import and export of controlled nuclear information, and recognizes that it is an offence for any person to export controlled nuclear information from Canada without an export permit issued for the purpose by the Canadian Nuclear Safety Commission. The Consultant agrees not to remove or cause to be removed from Canada any controlled nuclear information during the performance of the Services, and will promptly raise the issue with OPG where the Consultant is in doubt as to whether information to be removed from Canada as part of the Services may be – or contain – controlled nuclear information.

9. **Termination**

Torys may terminate this Retainer Agreement at any time on written notice to the Consultant. Torys will pay, or will cause OPG to pay, for work performed up to the date of the notice of termination. Upon the termination or expiration of this Retainer Agreement, the Consultant shall return to Torys or destroy any hard copies, and return to Torys and delete any electronic copies the Consultant may have of all documents and materials in its possession relating to the Services or this Retainer Agreement, including all Confidential Information (defined above) and Work Product, whether completed or not. The Consultant shall, upon request, provide Torys with a certificate of an officer of the Consultant certifying such destruction of hard copies and deletion of electronic copies.

10. **Liability and Indemnification**

The Consultant shall be liable for and shall indemnify and hold harmless Torys and OPG from all claims, demands, actions, penalties, direct damages, losses, judgments and settlements, liabilities, costs, expenses, including legal fees and other related costs and expenses arising out of, related to, or incident to, the Consultant or any of its representatives' performance of the Services under this Retainer Agreement, including, without limitation:

(a) any breach, violation or non-performance by the Consultant or any of its representatives of any terms, conditions, warranties, obligations or covenants contained in this Retainer Agreement

(b) any breach or violation by the Consultant or any of its representatives of any applicable laws; and

(c) any actions, omissions, negligence or wilful misconduct of the Consultant or any of its representatives.

11. **Limitation of Liability**

Except for breach of obligations under section 5 (Confidentiality), gross negligence, willful misconduct, fraud, breach of applicable laws, including but not limited to privacy laws, and the Consultant's obligation to indemnify under section 7 (Intellectual Property Protection), the Consultant's total liability for any claim arising out of the performance of the Services, regardless of the form of claim, will in no event exceed total fees paid to Consultant hereunder and under no circumstances will either party be liable for any damages in respect of any incidental, punitive, special, indirect or consequential loss, even if that party had been advised of the possibility of such damages including, but not limited to, loss of profits, loss of revenues, failure to realize expected savings, loss of data, loss of business opportunity, or similar losses of any kind.

12. **Insurance**

(a) Unless otherwise specified in this Retainer Agreement, the Consultant shall, during the term of this Retainer Agreement, and at its own expense, maintain and keep in full force and effect:

(i) commercial general liability insurance on an occurrence basis having a minimum inclusive coverage limit, including personal injury and property damage, of not less than one million Canadian dollars ($1,000,000.00) per occurrence, which shall be extended to cover contractual liability, products and completed operations liability, owners/contractors protective liability and must also contain a cross liability clause and a severability of interest clause, and must name OPG and its affiliates as additional insureds; and

(ii) errors and omissions insurance (professional liability) in the amount of not less than two million Canadian dollars ($2,000,000.00).[1]

(b) All insurance coverages and limits required to be maintained by the Consultant shall be primary to any insurance maintained by OPG, which shall be excess and non-contributory. Prior to the commencement of the delivery of the Services, the Consultant shall deliver to OPG a certificate of insurance which evidences the Consultant's compliance with this Section, including the provision of a thirty (30) day prior written notice of cancellation, non-renewal or adverse material change, to OPG. The Consultant agrees that the insurance described herein does in no way limit the Consultant's liability pursuant to the indemnity provisions of this Retainer Agreement.

13. **Independence**

By entering into this Retainer Agreement, the Consultant acknowledges and agrees that the Sponsors have received a copy of Rule 13A of the Board's *Rules of Practice and Procedure* concerning expert evidence, and agree to accept the responsibilities that are or may be imposed on them by that rule with respect to testimony before the Board. A copy of the rule and the relevant form are attached as Schedules 'B' and 'C' hereto.

14. **Responsibility Statement**

The Consultant agrees that the Services provided for herein will be performed in a timely, competent, professional manner in accordance with recognized professional consulting standards for similar services to be performed by a leading consulting advisory firm, and that adequate qualified personnel will be assigned for that purpose. If, during the performance of the Services or prior to the Board's issuance of final, non-appealable order(s) disposing of all relevant relief sought

[1] If Consultant maintains the insurance policies in 12(a)(i) and (ii) with limits denominated in US dollars, then those policies shall provide the US dollar equivalent of the limits in 12(a)(i) and (ii) based on the foreign exchange rate as of the date of this agreement.

in the Application, such Services prove to be faulty or defective by reason of a failure to meet such standards, the Consultant agrees that upon prompt written notification from Torys, such faulty or defective portion of the Services will be redone at no cost to Torys or OPG, up to a maximum amount equivalent to the cost of the Services rendered under this Retainer Agreement, or, at Torys' request, the Consultant will refund an amount equal to the amount paid for the faulty or defective portion of the Services.

15. **Entire Agreement**

This Retainer Agreement, together with all Schedules attached hereto and any agreements and other documents to be delivered pursuant to this Retainer Agreement, constitute the complete agreement between Torys and the Consultant or their respective agents with respect to the subject matter hereof and supersedes any and all prior agreements and understandings. This Retainer Agreement may be amended only in a written agreement that refers to this Retainer Agreement and is signed by both parties.

16. **Governing Law**

This Retainer Agreement shall be construed and otherwise governed pursuant to the laws of the Province of Ontario and the federal laws of Canada applicable therein.

Sincerely,

TORYS LLP

Per: ______________________
Name: Jonathan Myers

Accepted and agreed to by Concentric Energy Advisors, Inc.

Signed ______________________

Name (please print) Daniel S. Dane

(I have the authority to bind the Consultant)

SCHEDULE "A"

OPG's Standard Form Business Expense Schedule

(see attached)

STANDARD FORM BUSINESS EXPENSE SCHEDULE FOR CONTRACTORS

Effective June 17, 2009

ONTARIO POWER GENERATION INC.

Updated December 10, 2014 (R2)

Minor Revisions:

- R1 February 12, 2019 Minor revision to update AMEX contact information (December 10, 2014 R1)

- R2 July 17, 2020 Minor revision to update section 2.5 Travel expenses (December 10 2014 R2)

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BUSINESS EXPENSE SCHEDULE

RECITALS

A. Ontario Power Generation Inc., (**"OPG"**) entered into an Agreement (the **"Agreement"**) with the other party to the Agreement (the **"Contractor"**). This schedule (this **"Schedule"**) forms part of the Agreement. Under the Agreement, OPG agreed to reimburse the Contractor for certain business expenses incurred by employees of the Contractor (**"Eligible Employees"**) in performing work for OPG under the Agreement.

B. This Schedule sets out the terms on which OPG will reimburse the Contractor for business expenses incurred by Eligible Employees in performing work for OPG.

SECTION 1 – INTERPRETATION

1.1 Three Types of Reimbursement

OPG will reimburse the Contractor for expenses that are eligible for reimbursement in accordance with the Schedule. OPG will make the reimbursements in 1 of 3 ways respecting each Eligible Employee in respect of whom reimbursements are payable. The 3 ways of reimbursements are:

(a) reimbursement of individually incurred Allowable Expenses as set out in section 2 through section 5;
(b) payment on a flat rate daily basis as set out in section 6; or
(c) payment on a flat rate monthly basis as set out in section 7.

Except as expressly set out in section 6 or section 7, if OPG pays the Contractor the daily or monthly rate in respect of an Eligible Employee, OPG will reimburse the Contractor no Allowable Expenses in respect of that Eligible Employee.

1.2 Definitions

In this Schedule, the following terms have the respective meanings set out below.

(a) **Agreement** is defined in Recital A.
(b) **Allowable Expenses** is defined in Section 2.1.

(c) **Business Day** means any day other than a Saturday, Sunday, New Year's Day, Family Day, Good Friday, Easter Monday, Victoria Day, Canada Day, Civic Holiday, Labour Day, Remembrance Day, Thanksgiving Day, Christmas Day and Boxing Day.

(d) **Contractor** is defined in Recital A.

(e) **Eligible Employees** is defined in Recital A.

(f) **Home Base** means the permanent place of residence (home) of Eligible Employee.

(g) **Reporting Location** means the normal work location or base office for Eligible Employee. For all work at Darlington Nuclear (DN) and Pickering Nuclear (PN) sites, this is further defined as an area consisting of a 100km radius around the midpoint between DN and PN site. Bruce Nuclear (BN) is also considered a reporting location.

(h) **OPG Representative** is defined in Section 2.1 (d).

(i) **Schedule** is defined in Recital A.

(j) **Work Site** means a location at which the Eligible Employee may be required to provide service that is different from the Eligible Employee's normal reporting location.

1.3 Headings

The division of the Schedule into sections, the insertion of headings and the provision of a table of contents are for convenience of reference only and are not to affect the construction or interpretation of this Schedule.

1.4 Expanded Definitions

Unless otherwise specified, words importing the singular include the plural and vice versa and words importing gender include all genders. The term **"including"** means "including without limitations", and the terms **"include"**, **"includes"** and **"included"** have similar meanings. The term **"will"** means "shall".

1.5 Business Day

If under this Schedule any payment or calculation is to be made on or as of a day which is not a Business Day that payment or calculation is to be made on or as of the next day that is a Business Day

1.6 Payment Currency

Except as expressly set out in the Agreement, amounts to be paid or calculated under this Schedule will be paid or calculated in Canadian dollars. Any amounts to be paid or calculated which are denominated in a foreign currency will be converted into Canadian dollars, within three Business Days of the invoice date, using the Bank of Canada nominal noon exchange rate, as posted on the Bank of Canada website (currently located at www.bankofcanada.ca).

1.7 Conflict

If there is conflict between any term of this Schedule and any term in another part of the Agreement, the relevant term in the other part of the Agreement will prevail.

1.8 Notice

Any notices to be given under this Schedule will be given in accordance with the notice terms set out elsewhere in the Agreement.

SECTION 2 – REIMBURSEMENT OF ALLOWABLE EXPENSES

2.1 Allowable Expenses

OPG will only reimburse the Contractor for the following eligible expenses **(“Allowable Expenses”)** to the extent they otherwise meet the requirements of this Schedule and the rest of the Agreement:

(a) air, rail and bus travel expenses permitted under section 3;

(b) vehicle expenses permitted under section 4;

(c) lodging expenses permitted under section 5; and

(d) any other expenses which have been approved in writing by the OPG individual managing the Agreement (the **“OPG Representative”**).

2.2 Expenses Minimised

Notwithstanding any term in this Schedule, the Contractor will use all reasonable efforts to ensure that Eligible Employees minimise Allowable Expenses and the Contractor will ensure that all Allowable Expenses are reasonable and properly incurred in a manner consistent with effective and efficient business practice. OPG is not obliged to reimburse any expenses which are not so incurred. Eligible Employees who normally live together are expected to share accommodations and vehicle expenses, where reasonable.

2.3 Excluded Items

Notwithstanding any term in this Schedule, OPG will not reimburse any amounts to the Contractor or any Eligible Employee for any hospitality, food or incidental expenses, including, but not limited to, in respect of the following:

(a) meals, snacks, alcoholic and non-alcoholic beverages;

(b) any expense whatsoever if the one way distance between the Eligible Employee's Home Base or Reporting Location and the Work Site is less than 100 kilometers;

(c) gratuities;

(d) airline or railway club dues, fees or other charges;

(e) personal service expenses, including hair care, shoe shine, toiletry and spa treatment expenses;

(f) laundry, dry cleaning or valet expenses;

(g) hotel telephone charges or internet access;

(h) personal telephone calls;

(i) cellular telephones, data devices (for example, Blackberries) or other communication devices;

(j) entertainment or recreation expenses, including pay-per-view, video, compact disk or DVD rental, in-room entertainment, games, gaming, reading, sports or exercise expenses;

(k) headsets or other in-flight expenses;

(l) dependent care expenses;

(m) pet care expenses;

(n) mini bar charges or sundry items (including gum and snacks);

(o) credit card interest or other credit card expenses;

(p) automobile washes;

(q) fines or other expenses assessed or otherwise incurred in respect of traffic or parking violations; or

(r) fees or other expenses for toll highways or vehicle rental agency administration charges for use of toll highways.

2.4 Method of Reimbursement

OPG will reimburse the Contractor for Allowable Expenses which otherwise meet the requirements of this Schedule and the rest of the Agreement in accordance with the following terms.

(a) **Monthly Invoice.** The Contractor will deliver to OPG, to the address indicated in the purchase order or Agreement, on a monthly basis, an invoice for Allowable Expenses in a form and manner acceptable to the OPG Representative, acting reasonably. The Contractor will deliver to the OPG Representative, a copy of the invoice and will ensure that the invoice legibly itemises and, if necessary, briefly describes all allowable expenses. The Contractor will not invoice or otherwise charge OPG for any expenses other than allowable expenses. The Contractor will ensure that all expenses claimed on each such invoice meet the requirements of this Schedule and the rest of the Agreement and are first approved by the Contractor. If the Contractor fails to deliver an invoice to OPG for an expense within six months of the expenses being incurred, OPG will not be obliged to reimburse the Contractor for such expense.

(b) **Receipts.** The Contractor will deliver to the OPG Representative, together with a copy of the invoice, original official itemised receipts for each allowable expense claimed (including airline, railway or bus ticket passenger coupons or electronic ticket, boarding passes, vehicle rental contracts, itemised hotel bills and travel itineraries). The Contractor will separate expenses for each Eligible Employee. Debit card and credit card receipts are not acceptable without the itemised receipt. OPG will accept electronic, photocopied or fax copies of receipts.

(c) **GST/HST Deducted.** The Contractor will deduct all Canadian goods and services tax/harmonized sales tax levied under the *Excise Tax Act* (Canada) recovered or recoverable by the Contractor on the payment of expenses before submitting any invoice to OPG covering any allowable expenses. The Goods and Services Tax/Harmonized Sales Tax levied under the *Excise Tax Act* (Canada) and reimbursable by OPG under this Schedule.

(d) **Reimbursement.** OPG will reimburse the Contractor for Allowable Expenses which meet all of the requirements of this Schedule, received and approved by OPG before the 25th of each month on the 25th of the following month. The Contractor will ensure that all Eligible Employees initially pay for expenses using their own payment methods. OPG will not provide any advances respecting allowable expenses. The Contractor is exclusively responsible for the reimbursement of expenses to all Eligible Employees. Failure by the Contractor to comply with the requirements of this Schedule and the rest of the Agreement may result in delay of reimbursement of expenses or rejection of any invoice in whole or in part.

2.5 Travel Agency

OPG has negotiated rates with travel service providers to reduce travel and lodging expenses. Unless OPG provides the Contractor with written notice stating otherwise, or the Contractor can demonstrate it can obtain lower rates from providers other than AMEX Global Business Travel, the Contractor will ensure that all Eligible Employees performing services for OPG with approved travel expense reimbursement by OPG will process travel requirements through AMEX Global Business Travel. OPG encourages the Contractor to make all travel reservations, Air, Rail, Car Rental, and Hotel through AMEX Global Business Travel. AMEX Global Business Travel may be reached in Canada and the United States at 1-888-840-5165 from 8am to 8pm EST. The Contractor will ensure that all Eligible Employees traveling for the purpose of providing services to OPG under the Agreement identify themselves as OPG Contractors to AMEX Global Business Travel when calling and Eligible Employees will be require to provide their Date of Birth and their credit card for payment to AMEX Global Business Travel at time of making the travel arrangements.

2.6 Confirming Rates

The Contractor will ensure that the rates booked by it or an Eligible Employee are the same or lower than that listed on the travel itinerary.

2.7 Home Base and Work Site

Where applicable, the Contractor will specify in each invoice the Home Base, Reporting Location and the Work Site for each Eligible Employee. At OPG's request, the Contractor will provide written confirmation from each Eligible Employees as to the employee's permanent residence and street address. A post office box is not acceptable street address.

2.8 Non EPSCA Eligible Employees and Extended Staff

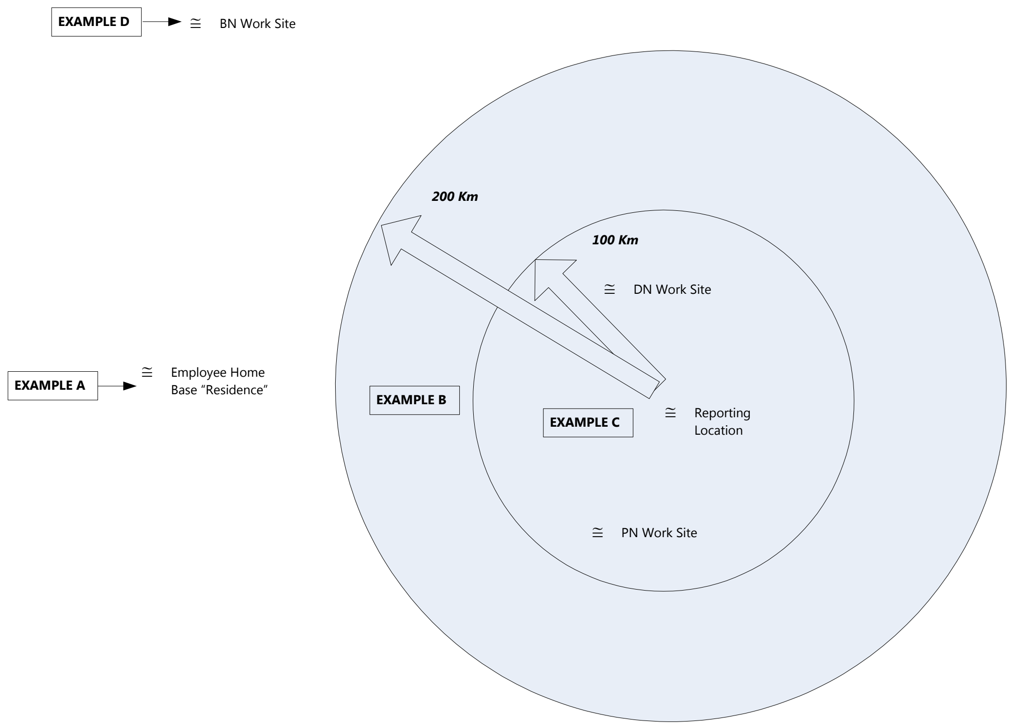
OPG will only reimburse the Contractor's Eligible Employees and extended staff, not subscribed to an EPSCA Agreement, expenses incurred from their Home Base to the designated reporting location as per the illustration below and detailed examples provided:

Example A: Home Base is outside the 200 kilometers ring from the reporting location. Prior approval from an OPG Representative is required and depending on the duration of the assignment, either section 6 or section 7 applies. If the duration is greater than one month, section 7 applies and the Eligible Employee will be paid an "all inclusive" monthly rate (or prorated portion of the month). If the assignment is less than one month, section 6 applies and the Eligible Employee will be paid an "all inclusive" daily rate.

Example B: Home Base is outside the 100 km ring but inside the 200 kilometers ring from the reporting location. Prior approval from an OPG Representative is required and OPG will pay the less of a daily "all inclusive" rate per section 6 or rates in accordance with sections 2 through 5. If sections 2 through 5 apply, the Eligible Employee will only be entitled to one round trip per week, from Home Base to the reporting location.

Example C: Home Base is within a 100 kilometers radius of the reporting location. In this scenario, the Eligible Employee is not entitled to any expenses whatsoever. This would include any and all trips to the Work Site within the 100 kilometers radius.

Example D: In this example, the reporting location and Work Site is one and the same. Prior approval from an OPG Representative is required and the preceding examples A, B and C apply.


EXAMPLE D
≅ BN Work Site
200 Km
100 Km
≅ DN Work Site
EXAMPLE A
≅ Employee Home Base "Residence"
EXAMPLE B
EXAMPLE C
≅ Reporting Location
≅ PN Work Site

SECTION 3 – AIR, RAIL OR BUS TRAVEL

3.1 Air, Rail or Bus Travel

The expense of air, rail and bus travel is an allowable expense to the extent the actual amount of airfare or, rail or bus fare was incurred by an Eligible Employee in providing services to OPG under the Agreement and to the extent of compliance with the other requirements of this Schedule and the rest of the Agreement. Pre approval by an OPG Representative is required for all air, rail or bus travel. The Contractor will cause Eligible Employees, to the extent possible, to take advantage of hotel and airport shuttles where available. OPG will reimburse the Contractor for the expenses actually incurred by an Eligible Employee for travel between the Eligible Employee's Home Base, reporting location or Work Site and the airport, rail way station or bus terminal where the Eligible Employee arrives or departs. In addition, the amount of any such reimbursement may not exceed the lesser of:

(a) the expense of the taxi fare or other similar out of pocket charge to travel to or from the airport, railway station or bus terminal; and

(b) if applicable, parking charges at the airport, railway station or bus terminal.

3.2 Economy Class

Air expenses are not Allowable Expenses unless the Eligible Employee travels on economy class or equivalent. Rail expenses will be permitted for travel by VIA 1 or equivalent.

3.3 Vehicle Instead of Air, Rail or Bus Travel

OPG will only reimburse the Contractor for use of a personal vehicle or rental car (the lesser of) for trips which would customarily be travelled by air, rail or bus, for the amount which is equal to the lesser of:

(a) the expense of the airfare, rail fare or bus fare that would have been reimbursed by OPG to the Contractor under section 3; and

(b) the amount that would otherwise be reimbursable by OPG to the Contractor for vehicle travel pursuant to section 4. OPG will not reimburse the Contractor for any lodging that would not have been incurred had the trip been made by air, rail or bus.

3.4 Visits Home

OPG will reimburse air, rail or bus travel expenses for a maximum of one round trip home per month for each Eligible Employee on assignment at a Work Site where the duration is more than 45 days and the Home Base of that employee is greater than 400 kilometers from the Work Site.

3.5 Minimising Expenses

The Contractor will, to the extent possible, cause all air travel, to be by "lowest logical airfare", to take advantage of weekend specials and other discount fares and to reduce overall expenses and plan ahead (booking at least 2 weeks before the departure date is expected).

SECTION 4 – VEHICLES

4.1 Reimbursable Vehicle Expenses

The expense of rental vehicles or personal vehicles (the lesser of) used by Eligible Employees will be and allowable expense to the extent that:

(a) the use of the vehicle was for official OPG business;

(b) the one way distance between the Eligible Employee's reporting location and the Work Site is greater than 100 kilometers;

(c) the use of the rental vehicle was pre-approved in writing by the OPG Representative; and

(d) the expense otherwise meets the requirements of this Schedule and the rest of the Agreement.

4.2 Personal Vehicle

If the Eligible Employee is required to provide services at a location other than the Eligible Employee's reporting location, OPG will reimburse the Contractor as an allowable expense for all personal vehicle travel by an Eligible Employee in excess of 200 kilometers (round trip), at the published rates per kilometre on the date of invoice, for vehicle expenses for Ontario set on the Canada Revenue Agency website (www.cra-arc.gc.ca/tx/llrts/menu-eng.html). This Canada Revenue Agency amount covers all vehicle related expenses, except parking.

4.3 Reducing Expenses

The Contractor will use all reasonable attempts to reduce the expenses of vehicle travel by:

(a) arranging for employees to share vehicles to minimise travel expense;

(b) requiring Eligible Employees to use rental vehicle and refuel it before returning it;

(c) considering a long-term lease for lengthy work assignments (that is, more than 30 consecutive days) when the Eligible Employee requires a rental vehicle; and

(d) requiring Eligible Employees to use public transit when travelling to locations within or around urban centres.

4.4 Multiple Users

OPG will only reimburse the Eligible Employee whose vehicle is used when two or more Eligible Employees travel in one vehicle. If two or more Eligible Employees share a rental vehicle, OPG will only reimburse the Eligible Employee who incurred the expense.

SECTION 5 – LODGING

5.1 Overnight Accommodation

The expense of overnight accommodation for Eligible Employees will be an allowable expense to the extent that the overnight stay was pre-approved in writing by OPG Representative and to the extent that the expense otherwise meets the requirements of this Schedule and the rest of the Agreement. The OPG Representative will not approve any overnight accommodation unless:

(a) the presence of the Eligible Employee is required at a Work Site which is more that 200 km (one way) from that Eligible Employee's reporting locations or;

(b) poor weather creates hazardous driving conditions and the Eligible Employee cannot safely return to the Eligible Employee's Home Base;

(c) the Contractor will include a written explanation for all overnight accommodation with the invoice.

SECTION 6 – DAILY RATES

6.1 Daily Rates Instead of Allowable Expenses

To the extent this section 6 applies to any Eligible Employee, none of the terms of section 2 to section 5 apply, except for any Allowable Expenses for air, rail or bus travel between an Eligible Employee's reporting location and a Work Site that is reimbursable in accordance with section 3. Notwithstanding the previous sentence, the temporary residence (where the Eligible Employee resides while working on the OPG project), or in some instances the Home Base will be considered the reporting location for the purpose of calculating Allowable Expenses in the event the Eligible Employee is required to travel to a location other than the reporting location.

6.2 Daily Rates

Before the commencement of, or at any time during, a work assignment for any Eligible Employee, OPG may elect based on the remaining duration of the work assignment, the distance between the Eligible Employee's reporting location and the work site or for other reasons to pay the Contractor a daily rate in respect of that Eligible Employee rather than to reimburse the Contractor for allowable expenses.

6.3 All Inclusive

Except as expressly set out in this section 6, the daily rate set out in section 6.4 is inclusive of all expenses whatsoever that will be reimbursed by OPG, including expenses respecting accommodation, local transportation, work permits and fees, utilities, communication charges, furnishings, insurance and any Allowable Expenses that would otherwise be reimbursable to the Contractor under section 2 to section 5.

6.4 Rates

Subject to adjustment under section 6.5, the following are the daily rates that OPG will pay the Contractor in respect of Work Sites:

(a) City of Toronto, $150 and;

(b) all other locations, $120 (including Mississauga, Pickering, Whitby and Darlington).

6.5 Application of Rate

Where OPG has elected to pay the daily rate for an Eligible Employee, OPG will pay the daily rate to the Contractor on a monthly basis for that Eligible Employee for each full day that the Eligible Employee provided services under the Agreement and for each weekend day unless the Eligible Employee surrendered his or her accommodations. The daily rate will not be paid for any period of an unexcused absence or when the Eligible Employee has surrendered the Eligible Employee's accommodations during a home visit or absence (includes unavailability to work on weekends if trip home was taken on the weekend). The daily rate will be reduced by $35 for each day of approved trips home and on the last day of providing services under the Agreement. Where OPG has elected to pay the daily rate for Eligible Employees who normally live together, the Eligible Employees are expected to share accommodations. Adjustments may be made to the daily rate set out in section 6.4 if Eligible Employees share accommodations and other expenses.

6.6 Method of Reimbursement

OPG will pay the Contractor the applicable daily rate in accordance with the following terms:

(a) **Monthly Invoice.** The Contractor will provide OPG, on a monthly basis, with an invoice listing the number of Eligible Employees from whom the Contractor is claiming the daily rate and the number of days being claimed for each Eligible Employee. The Contractor will ensure that the invoice includes a description of the work package or project name and project number (and work breakdown structure element if applicable).

(b) **Evidence of Expenses.** The Contractor will provide OPG with original or electronic photocopies itemised receipts and time sheets evidencing that the Eligible Employee attended the Work Site and made use of temporary accommodation on each day for which the daily rate is being requested. Debit card and credit card receipts are not acceptable without the itemised receipt. Failure by the Contractor to comply with the requirements of this Schedule and the rest of the Agreement may result in delay of reimbursement of expenses or rejection of any invoice whole or in part.

6.7 Absences

Unless authorised in writing by the OPG Representative, OPG will not be required to pay daily rates for an Eligible Employee where that Eligible Employee was absent from the Work Site without having been excused by the OPG Representative or where that Eligible Employee did not make use of the Eligible Employee’s accommodations during an absence for the Work Site (other than an absence required to perform services to OPG under the Agreement). The OPG Representative may consider authorising payment of the daily rate for absences such as an infrequent sick day or medical appointments requiring exams or tests.

Section 7 – MONTHLTY RATES

To the extent this section 7 applies to any Eligible Employee, none of the terms of section 2 to section 6 apply, except for any Allowable Expenses for air, rail or bus travel between and Eligible Employee’s reporting location and a Work Site that is reimbursable in accordance with section 3. Where OPG elects to pay on a monthly basis in respect of any Eligible Employee, OPG will pay the Contractor $1800 per month (on pro-rated portion of a month). All the terms of section 6 apply to the calculation of this monthly rate, with such modifications as the circumstances require.

Schedule "B"
Rule 13A of the Board's Rules of Practice and Procedure

13A. Expert Evidence

13A.01 1 Where a party intends to engage one or more experts to give evidence in a proceeding on issues that are relevant to the expert's area of expertise, **Rule 13** applies to that evidence.

13A.02 An expert shall assist the OEB impartially by giving evidence that is fair and objective.

13A.03 An expert's written evidence shall, at a minimum, include the following:

(a) the expert's name, business name and address, and general area of expertise;

(b) the expert's qualifications, including the expert's relevant educational and professional experience in respect of each issue in the proceeding to which the expert's evidence relates;

(c) the instructions that party provided to the expert in relation to the proceeding and, where applicable, to each issue in the proceeding to which the expert's evidence relates;

(d) the specific information upon which the expert's evidence is based, including a description of any factual assumptions made and research conducted, and a list of the documents relied on by the expert in preparing the evidence;

(e) in the case of evidence that is provided in response to another expert's evidence, a summary of the points of agreement and disagreement with the other expert's evidence; and

(f) an acknowledgement of the expert's duty to the OEB in **Form A** to these Rules, signed by the expert.

13A.04 In a proceeding where two or more parties have engaged experts, the OEB may require two or more of the experts to:

(a) in advance of the hearing, confer with each other for the purposes of, among others, narrowing issues, identifying the points on which their views differ and are in agreement, and preparing a joint written statement to be admissible as evidence at the hearing; and

(b) at the hearing, appear together as a concurrent expert panel for the purposes of, among others, answering questions from the OEB and others as permitted by the OEB, and providing comments on the views of another expert on the same panel.

13A.05 The activities referred to in Rule 13A.04 shall be conducted in accordance with such directions as may be given by the OEB, including as to:

(a) scope and timing;

(b) the involvement of any expert engaged by the OEB;

(c) the costs associated with the conduct of the activities;

(d) the attendance or non-attendance of counsel for the parties, or of other persons, in respect of the activities referred to in paragraph (a) of **Rule 13A.04**; and

(e) any issues in relation to confidentiality.

13A.06 A party that engages an expert shall ensure that the expert is made aware of, and has agreed to accept, the responsibilities that are or may be imposed on the expert as set out in this Rule 13A and **Form A**[2].

[2] Attached as Schedule 'C herein.

SCHEDULE "C"

FORM A

Proceeding: EB-2025-0297

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Daniel S. Dane (*name*). I live at Northborough (*city*), in the State (*province/state*) of Massachusetts

2. I have been engaged by or on behalf of OPG (*name of party/parties*) to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

(a) to provide opinion evidence that is fair, objective and non-partisan;
(b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
(c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date December 9, 2025

____
Signature

INITIAL FINANCING FOR DARLINGTON NEW NUCLEAR PROGRAM

EVIDENCE OF CLIFF INSKIP

December 4, 2025

Table of Contents

A. Introduction and Purpose

My name is Cliff Inskip, and I am the President of Polar Star Advisory Services Inc., a consulting firm that focuses on advising government and corporate clients on infrastructure and project financing matters. I have been retained by Ontario Power Generation Inc. ("OPG"), to provide expert opinion and testimony on the expected availability of non-recourse, investment grade debt financing within 12-18 months of the in-service date of the first of four planned Small Modular Reactors ("SMR") being developed by OPG on its Darlington New Nuclear site (the "DNNP" or the "Program"). 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. OPG is an electricity producer supplying approximately one half of Ontario's energy generation. It is wholly owned by the Province of Ontario.

OPG expects the SPV to be the Ontario Energy Board ("OEB") licence holder for the DNNP facilities and be prescribed for electricity rate-regulation pursuant to the *Ontario Energy Board Act, 1998* and associated Ontario Regulation 53/05. As such, OPG expects to seek the OEB's approval, on behalf of the SPV, of (i) the SPV's revenue requirements, including cost of capital amounts, and (ii) the SPV's production forecast, for the 2027-2031 period, with both being sought in conjunction with OPG's upcoming 2027-2031 payment amounts application to the OEB. This testimony is intended to inform the capital structure to be sought by the SPV for the DNNP facilities for the purpose of the OEB's approval of the relevant revenue requirements over this upcoming period.

I understand that my opinion may be relied upon as expert evidence. I understand that I am obliged to provide evidence that is fair, objective and non-partisan and only on matters within my areas of expertise. I understand that these duties prevail over any obligation which I may owe to any party on whose behalf I have been retained.

My compensation does not depend on the nature of my opinion contained herein.

To the best of my knowledge, I do not have any conflicts of interest with respect to the matter for which I have been asked to provide my opinion.

B. My Qualifications

I spent most of my career advising equity sponsors and arranging debt for infrastructure, utility, quasi-government and project finance transactions with institutional investors. I worked five years with Export Development Canada (three years as an international lender) followed by 29 years with CIBC/CIBC World Markets and its affiliates in Canada and in the UK (including eight years as a lender and 19 years as an investment banker). When I retired from CIBC World Markets at the end of 2014, I was Managing Director, Head of Infrastructure & Project Finance, responsible for leading a team that advised equity sponsors and arranged bond financing for infrastructure related clients and projects. I had a very strong focus on advising new issuers who had never accessed the bond market.

As part of my role, I was actively involved in risk assessment of projects and advising on and preparing credit rating presentations. I advised numerous utilities and power generators on obtaining their inaugural credit ratings including Arrow Lakes Power Corporation, Lower Mattagami Energy Limited Partnership, Hydro Ottawa Holding Inc., Powell River Energy Inc., Hamilton Utilities Corporation, Lake Superior Power L.P., North Battleford Power L.P., Spy Hill Power L.P., and many others outside the power and utilities sector such as Maritimes & Northeast Pipeline Limited Partnership, British Columbia Ferry Services Inc. and the North West Redwater Partnership.

I also advised on or/and arranged structured project financing for corporate clients such as Northland Power Inc. (e.g., Spy Hill Power L.P., North Battlefield Power L.P.), Brookfield Renewable Power Inc. (e.g., Great Lakes Power Trust, Powell River Energy Inc., Lake Superior Power Inc., Lievre Power Financing Corporation), Maritimes & Northeast Pipeline Limited/Spectra Energy Corporation, Westcoast Energy Inc., Enbridge Consumers Gas (now Enbridge Gas Distribution Inc.), North West Water (now United Utilities Group plc) and Canadian Natural Resources Limited. I advised several governments and quasi-government entities regarding public private partnerships and infrastructure transactions including the Province of Alberta, Infrastructure Ontario, the City of Winnipeg, OPG and Columbia Power. My bond arranging and advisory experience includes the following sectors: airport, port, refinery, pipeline, highway/bridge, university, school board, gas processing, and power generation. I have arranged bond financing for several regulated utilities including six Fortis Inc. subsidiaries, Toronto Hydro Corporation, Hamilton Utilities Corporation, Hydro Ottawa Holding Inc. and Enersource Corporation, among others. In placing bonds in the market for these companies, I interacted extensively with institutional investors.

Since retiring from CIBC/CIBC World Markets, I have consulted on various large infrastructure projects and have served on several boards of directors including those of a major Canadian based pension fund, a regulated utility and an independent power developer/operator active in emerging markets. I have also been a member of several Investment Committees.

As a lender, advisor, bond underwriter or member of Finance/Audit and Investment Committees, I have extensively structured, analyzed or reviewed dozens of major transactions in Canada and, to a lesser extent, around the world.

I have attached my current curriculum vitae as *Appendix A* to this evidence. As noted therein, I have a B.A.Sc. in civil engineering and an MBA from the University of British Columbia as well as a diploma in corporate treasury management from the Association of Corporate Treasurers (UK). I maintain in good standing the following designations: CFA (Chartered Financial Analyst) and FRM (Financial Risk Manager from the Global Association of Risk Professionals) as well as P.Eng (Professional Engineers Ontario) and C.Dir. (Chartered Director, McMaster University / Directors College). I also previously held FCT (Fellow of Association of Corporate Treasurers, UK) and FCSI (Fellow of Canadian Securities Institute) designations.

C. Summary of Testimony

A special purpose vehicle is expected to be set up to develop, construct and operate the four planned SMRs as part of the DNNP. The SPV is expected to be a limited partnership (LP) that enters a lease arrangement with OPG for the DNNP site and premises. The DNNP is expected to be funded entirely with equity until completed SMRs start to enter service. The primary source of equity will be OPG (expected to be through a financing entity), with additional equity to be provided by CGF and BOF as minority investors. 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. Units 2, 3 and 4 are expected to be in various stages of development/construction at the in-service date of Unit 1. I understand that proceeding with the construction of Units 2, 3 and 4 is subject to future organizational and regulatory approvals.

The SMRs will utilize GE Hitachi BWRX-300 technology. Unit 1 will be the first unit in the world utilizing the selected technology. The most recent boiling water reactor ("BWR") technology (i.e., the Advanced Boiling Water Reactor) that was in use is the large-scale reactor technology which was developed in the early 1990s and was used in Japan prior to the Fukushima event in 2011. Unlike CANada Deuterium Uranium ("CANDU") technology used in OPG's existing larger scale reactors at its Darlington and Pickering sites, BWRs utilize enriched uranium.

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.

While any one risk may not on its own detract from potential bond investors' willingness to invest in the SPV, risks are not viewed in isolation and aggregated risks can result in a risk profile that is more challenging than any single risk. Bond investors, by nature, exhibit conservatism and prioritize capital preservation, leading them to be particularly averse to risks, including those with low probability but potentially high impact. The risk premium/credit spread for investment grade bonds does not compensate investors for FOAK nuclear technology risk and so, at a minimum, potential bond investors will want to have the benefit of a reasonable period of satisfactory operation of the first SMR unit prior to purchasing bonds. An initial satisfactory operating period may also be necessary to obtain even the lowest investment grade credit ratings.

The SPV will want a sufficiently broad distribution of the first bond issue to set the tone for future issuances. Issuing a bond for a first-time issuer such as the SPV requires extensive preparation, which I expect would take at least 6-9 months after Unit 1 comes into service. Even in the absence of other considerations, this would limit how quickly after the Unit 1 in-service date that bond financing could realistically be completed. 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.

Finally, it will be important to determine whether, and if so what, steps could be taken to structure the financing to manage the initial bondholders' risk exposure associated with one operating unit (Unit 1) and simultaneous construction of Units 2, 3 and 4 within the SPV. This will need to be negotiated as part of the bond trust indenture (discussed below).

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.

D. Materials Relied Upon

I received and reviewed a variety of documents concerning the DNNP. The documents and information that I reviewed and relied on to understand the DNNP are listed in *Appendix B* attached hereto.

The depth and scope of my review of each document depended on the nature of the document and my assessment of its relevance to the opinion and testimony I have been asked to provide.

I was also provided with certain information orally from OPG that I used to augment Section E of this report (Relevant Facts) as well as certain information to augment my comments on Fuel Chain Risk and Supply Chain Risk (Section F, Part II, Questions 8 and 9 respectively).

E. Relevant Facts and Assumptions

My understanding is that:

1. When completed, the DNNP is expected to consist of four SMRs utilizing the substantially but not yet fully finalized GE Hitachi BWRX-300 technology. The first unit is expected to be in operation in October 2030 and is currently

under construction. Subject to various approvals to proceed, the other units are expected to be under construction at or shortly after the time Unit 1 is put in service.

2. OPG is expecting to develop the DNNP through an SPV structure, which will facilitate outside equity investment in the project. The SPV will hold all DNNP SMRs that are approved to proceed throughout their construction and operation. The SPV is expected to be a limited partnership with OPG and/or related parties being the majority owners. The SPV will have no employees as it will contract with OPG to provide all required services.

3. The parties have announced that equity investments by CGF and BOF will be made during the construction phase of the DNNP, subject to satisfaction of conditions, with each such government-related entity expected to be a limited partner investor in the SPV.

4. It is expected that OPG, as the owner of the Darlington New Nuclear site, will lease the required land to the SPV pursuant to a lease agreement. Leasehold improvements would include the SMRs, developed and constructed by OPG for the SPV pursuant to a project management agreement. Once in service, the SMRs would be operated by OPG on behalf of the SPV pursuant to an operating agreement. OPG would retain all necessary licences from the Canadian Nuclear Safety Commission ("CNSC"). The SPV would receive payment for power generated by the SMRs from the Independent Electricity System Operator ("IESO"), based on regulated rates established by the OEB. OPG has advised that it assumes it will collect blended payments from the IESO for its existing regulated nuclear fleet and as agent for the SPV and will then allocate the appropriate portion of funds to the SPV pursuant to a payments' allocation agreement. While OPG will be contractually bound to perform in accordance with these agreements, OPG will not provide any performance guarantees relating to the SMRs.

5. It is expected that the SPV will be regulated by the OEB on a stand-alone basis and that OPG would, on behalf of the SPV, seek approval of the SPV's revenue requirement based on the forecast of costs incurred directly or indirectly through the various contracts with OPG (without markup) and of the SPV's production forecast. I assume that the SPV's rate base will be based on DNNP project costs (leasehold improvements) and its authorized cost of capital will be based on a standalone capital structure. I further

assume that, after an SMR comes online, the SPV's rate-setting framework will be similar to OPG's in that it will be at risk for variances relative to forecast generation.

6. OPG and the equity partners are expecting to seek SPV non-recourse (to OPG and other partners) bond financing from capital markets as soon as practicable following the first SMR in-service date. 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. It is expected that all cash flows from the SPV will be available in the normal course to operate the SMR and service the debt, before any equity distributions. 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.

7. Following the service life of the SMRs, it is expected that the lease will end and OPG will be responsible for decommissioning the SMRs including obtaining the CNSC licence to decommission as well as for the management of nuclear waste and spent nuclear fuel (both during and after SMR operations).

F. Discussion and Opinion

PART I: - Introduction

1. **At a high level, what is your understanding of DNNP from the current construction phase to the debt repayment phase?**

The SPV is expected to develop, construct and operate the first commercially operated SMR in North America or any G7 country. Based on my research, there are only three SMRs in operation anywhere in the world: Russia has two floating SMRs in operation and China has a land based SMR in commercial operation. Subject to obtaining the requisite approvals, the SPV will eventually construct four SMRs at OPG's Darlington New Nuclear site. The SMRs utilize GE Hitachi Nuclear Energy's BWRX-300 technology. Each unit is designed to generate approximately 300 MW, which is about 30% of the output of each of OPG's existing large traditional CANDU reactors at the Darlington site.

The four SMRs are planned to be developed using "staged execution" so that learnings from the first unit's construction can be applied to deliver cost and time savings on the subsequent units. The first unit is expected to be in commercial operation in October 2030 and is currently under construction. The four units will share some common infrastructure which will be constructed with the first unit.

All the output from the four units will be offered and generated in the IESO Administered Market and is expected to receive the OEB approved regulated rate. It is expected that this regulated rate will be designed to recover SPV's costs and provide a return on equity. The regulated rate (for delivered electricity) is expected to be based on a forecasted revenue requirement, an opening rate base and the OEB-determined standalone capital structure and prescribed rate of return. Assuming alignment with OPG's rate term, the SPV's initial rate term would be 2027-2031. I assume that the rate set for the SPV will include the Unit 1 in-service amount starting in 2030, on a forecast basis. I assume that OPG is expected to return to the OEB on behalf of the SPV to seek a revised regulated rate to be effective for the SMRs for the 2032-2036 term. The start of such future rate term would be approximately 12-18 months after the scheduled in-service date of Unit 1. While some uncertainties will likely remain, at the time of re-applying to the OEB, additional information on various inputs for the SPV rate setting (e.g., final capital cost, revised production forecast and updated actual capital structure) should be available.

It is expected that OPG will collect funds for SMR delivered power from the IESO and pay them to the SPV. I assume that there will be a cash waterfall arrangement agreed with any potential lenders which will specify cash priorities. Typically, this would require payment of all operating costs, followed by debt service payments, replenishment of reserves (for debt service, short term maintenance, etc.) and finally distributions to equity holders. The details of the cash waterfall would need to be negotiated at the time of a debt offering.

All four units are expected to be within a common SPV financing framework, and there will be at least some interaction risks between the various SMR units. For example, if there are problems associated with Unit 2, 3 or 4 during construction or after being put into service, the problem could spill over and impact any bondholders who provided financing when only Unit 1 was operating. It will be important to determine whether, and if so what, steps could be taken to structure the financing to manage such a risk to the initial bondholders.

2. **To what extent has the perception of institutional investors evolved with respect to general willingness to purchase bonds issued by owners of Canadian nuclear facilities?**

The impact of nuclear safety has been a topic of debate since the first nuclear reactors were constructed in the 1950s and has been a key factor in historical public concern about nuclear facilities. Over time, there have been several accidents with varying impacts as well as near misses and incidents. According to the World Nuclear Association, "[i]n the 60-year history of civil nuclear power generation, with over 18,500 cumulative reactor-years across 36 countries, there have been only three significant accidents at nuclear power plants: Three Mile Island (USA 1979)..., Chernobyl (Ukraine 1986)..., and Fukushima Daiichi (Japan 2011)...".

Technical and other measures such as enhanced design, rigorous maintenance, and strengthened regulatory oversight, including measures like redundant backup systems, stronger containment, and better preparedness for extreme events, have been adopted to reduce the risk of accidents.

Given the ongoing transition to clean energy, increased demand for electricity, improvements in safety, advancements in nuclear technology, and increased focus by individual countries on energy security, there has been increased public acceptance and increased investment interest in nuclear generation facilities. While some public perception challenges may remain, it is my understanding and experience that views amongst institutional bond investors have evolved and now demonstrate a willingness to invest in Canadian nuclear generation facilities (e.g., Bruce Power LP). Thus, I do not see the fact that the DNNP is in the nuclear sector, in and of itself, to be an impediment to accessing the institutional bond market.

PART II: - Key Investment Related Risks (Bond Investor's Perspective)

A utility operating in a single jurisdiction with generally predictable and balanced regulation would typically be considered relatively low risk by bond investors. However, the DNNP has some unique characteristics/risks. While the discussion below is not intended to cover all risks, I have identified what I consider to be ten of the most significant ones for an in-service asset from the perspective of a potential bond investor. Below I have assessed these risks at a high level to determine which, if any, are likely to be impediments to obtaining successful bond financing within 12-18 months of the first SMR's in-service date. While I have reviewed each of the identified key risks generally in isolation from each other, bond investors will consider the aggregate risk profile that results from all relevant risks combined. These key risks, including the aggregate effect, would be assessed in greater detail by potential bond holders and credit rating agencies near the time of a bond offering based on prevailing circumstances at that time. My opinion is based on the macro-contextual conditions and the understanding of the facts as they exist today.

1. **Are institutional investors willing to accept FOAK nuclear technology risk? How significant is this risk from a potential bond investor's perspective?**

Based on information from the U.S. Nuclear Regulatory Commission website and elsewhere, the BWR technology was originally developed in the 1950s (see *Exhibit C*) and evolved through six different designs (BWR/1 in 1960 to BWR/6 in 1981).

The first Generation III Advanced Boiling Water Reactor ("ABWR") began commercial operation in Japan in 1996. GE-Hitachi's Economic Simplified Boiling Water Reactor ("ESBWR"), a Generation III+ reactor with advanced passive safety systems, was certified by the U.S. Nuclear Regulatory Commission in 2014 but was never built. The ESBWR was developed based on concepts from the earlier Simplified Boiling Water Reactor ("SBWR") design which was also approved but never built.

Factors such as public and political resistance, economic challenges (including costly and complex construction and competition from cheaper energy sources), and regulatory hurdles (e.g., higher safety standards and better preparedness for extreme events) arising because of previous nuclear accidents discouraged the construction of new nuclear reactors in the early part of the 21st century.

According to GE Vernova's website, the BWRX-300 technology development was launched in 2017. In 2022, OPG signed a contract pursuant to which the DNNP site in Clarington, Ontario, Canada, would be the first site in the world to deploy the next generation SMR technology (BWRX-300). In 2023, three power companies from the U.S. (Tennessee Valley Authority), Canada (OPG), and Poland (Synthos Green Energy) agreed to invest in developing the standard plant design for the BWRX-300 reactor for their respective countries.

As noted above, BWRX-300 SMRs are not based on ready-to-deploy technology and, when fully finalized, they will be FOAK technology. While the ESBWR and SBWR technologies were approved a decade ago, they were never built. The last BWR technology that was built was based on technology developed some thirty plus years ago.

The DNNP will utilize a mix of proven and FOAK technology. FOAK equipment could include components that are entirely new or that have undergone significant modification, novel applications of existing technologies including first time use in nuclear operations, or components that have never been used in a nuclear regulated environment in Canada. Although OPG is regarded as a proficient and experienced nuclear utility and has taken steps to plan and prepare for the DNNP, these FOAK components come with inherent risks that cannot be fully mitigated. The risks could require additional testing, inspections, adjustments, design changes, etc., some or all of which could necessitate outages or down-powers to address after the unit is in operation.

The unknown risks associated with FOAK nuclear technology are the ones that I expect potential bond investors will be largely unwilling to accept without a reasonable period (at least 12-18 months) of satisfactory asset operation. 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 vs forecast electricity generation levels. Global developments in BWRX-300 technology prior to and after the in-service date could also impact investor sentiment positively or negatively.

Bond investors, by nature, exhibit conservatism and tend to prioritize capital preservation, leading them to be particularly averse to risks, even those with low probability but potentially high impact. This conservative mindset means they often focus on bonds issued by companies with predictable cash flows and minimal default risk. I expect potential bond investors will be quite cautious about technological risk as, in a worst-case scenario, this risk could result in a binary outcome (i.e., the SMR performs as expected, or it does not perform).

While OPG has taken steps (e.g., technical collaboration agreement with two international partners) to proactively mitigate FOAK risks associated with the design and construction of the plant, as a nuclear asset with no existing fleet of other commercially operating SMRs, the initial operation of Unit 1 inherently carries what bond investors will consider significant uncertainties with potentially material ramifications.

Bond investors will be aware of the potential implications of technology risks based on past in-service assets outside the nuclear sector. The examples which follow are in unrelated sectors and are not intended to be comparable to the DNNP; however, they are intended to demonstrate the potential magnitude of technological risk associated with non-diversified in-service assets.

A well-known Canadian example of technological risk is BC Ferries' effort to introduce a specific type of high-speed aluminum double hulled catamaran ferries with a unique design to its fleet. The three vessels cost over $450 million to build and were in operation for varying periods up to nine months. They were ultimately determined to be unfit for purpose and were sold for about $20 million. Among problems reported by varying sources, the CBC reported that "the vessels were taken out of service after being plagued by mechanical problems and concerns about the large wake they caused" which required reduced speed or altered course to avoid shoreline impact.

Another Canadian example of a project with major issues after the in-service date is the Confederation Line Transit project ($2+ billion for initial phase) in Ottawa which had numerous service disruptions caused, in part, by faulty components and issues with the modified design of the trains. The Ottawa Citizen reported that to create the train variant (named the Spirit) for the Confederation Line, Alstom had adapted the Citadis Dualis vehicle (more than 1,500 vehicles sold worldwide and more than 245 million kilometers in service). "Changes had been made to the propulsion system to accommodate different braking and acceleration "parameters" [and] crucially the vehicle's systems had been "winterized" to accommodate temperatures as low as – 40 C." The Ottawa Citizen went on to say: "The Spirit was to be the first Citadis model sold in North America — which made Ottawa the lead customer, with all of the uncertainties that that entailed." The Ottawa Citizen also reported that one of its sources indicated that "Alstom is tweaking [vehicles ordered by Metrolinx for Toronto] to deal with a series of technical issues that have plagued the Ottawa system — malfunctioning doors, brakes, power systems and communications between the vehicles and the LRT system". A senior Metrolinx media officer indicated that "Metrolinx and Alstom will be the beneficiaries of lessons learned (in Ottawa)."

A third example of technological risk following the in-service date is the Boeing 737 MAX. Two fatal crashes in 2018 and 2019 led to a worldwide grounding of the aircraft. The crashes were determined to be caused by flight control software which was inadvertently activated by a faulty sensor, forcing the aircraft's nose down and overwhelming pilots. While the aircraft has since been redesigned and cleared to fly, Boeing suffered direct costs of ~$20 billion and has faced ongoing issues with production quality, leading to increased regulatory scrutiny and production limits.

Potential bondholders will view technology risk as a risk to be borne by equity holders. Sometimes terms can be structured to insulate bondholders from taking certain key risks. I have been actively involved with Canadian bond issues where project sponsors agreed to build protections into the financial structure to address post completion technology and other material risks that debt investors were not prepared to accept.

An example of this type of protection involved a "hell or high water" (i.e., unconditional) commitment for the North West Redwater Partnership refinery project that ensured cash flowed from the off-taker even if the project was not complete or, if complete, it did not operate as planned. This concept could apply to the DNNP if, for example, the regulated price of electricity involved fixed (i.e., not based on electricity production), and not just variable, components. If appropriately structured, this approach could make bond financing near the in-service date of Unit 1 easier to put in place.

Another example involves the use of long-term cash traps or escrow accounts where available cash that would otherwise be distributed to shareholders is retained if certain future conditions are not met. An example is Maritimes & Northeast Pipeline Limited Partnership where satisfying a future test related to the level of proven and probable gas reserves was required in order to make dividend payments beyond the specified test date. However, this concept is unlikely to apply in situations where a risk is binary (e.g., FOAK nuclear technology risk) and where there are no other sources of revenue for the borrower other than the asset in question.

Overall, it is my conclusion, given the potentially binary nature of the technology risk for the DNNP, and the absence of an existing operating fleet of BWR SMRs anywhere in the world, that bond investors will not invest (regardless of credit spread) in the SPV until they are reasonably satisfied with the technology risk.

In my opinion, based on close to two decades of bringing first time bond issuers to market, inherently unknown FOAK nuclear technology risk is the SPV's biggest risk to raising debt following the Unit 1 in-service date. Bond investors will want sufficient time to observe and assess this risk and credit ratings/reports are likely to also benefit from such a period of observation and assessment.

Furthermore, given what I expect will ultimately be a large, multi-year borrowing program for the four SMR units, it will be easy for potential interested bond investors to wait for a subsequent offering if they are unsure about technology risk and/or want to observe the first SMR in operation for an acceptable period prior to investing. If the SPV seeks bond financing too early, potential bond investors could refrain from such an offering to first assess its success, and, of course, if too many potential bond investors take this approach, the initial "too-early" bond offering will not be successful.

2. **How will potential bond investors view safety and security risk associated with SMRs after the in-service date?**

Like other nuclear plants, the SMRs are subject to extensive licensing and regulatory obligations designed to protect health, safety, security and the environment from the risks associated with nuclear energy and materials. This includes the proper handling, packaging and transport of nuclear substances. In Canada, the regulatory authority for these matters falls to the CNSC.

The BWRX-300 reactor is a water-cooled, natural circulation SMR with passive safety systems (see *Exhibit D*). According to the International Atomic Energy Agency ("IAEA"):

> "in comparison to existing reactors, proposed SMR designs are generally simpler, and the safety concept for SMRs often relies more on passive systems and inherent safety characteristics of the reactor, such as low power and operating pressure. This means that in such cases no human intervention or external power or force is required to shut down systems, because passive systems rely on physical phenomena, such as natural circulation, convection, gravity and self-pressurization. These increased safety margins, in some cases, eliminate or significantly lower the potential for unsafe releases of radioactivity to the environment and the public in case of an accident."

According to the European Union ("EU") website, relative to traditional larger scale reactors, SMRs have passive safety systems, with a simpler design and fewer components (such as valves, pipes, safety grade pumps, and cables, which reduce the potential points of failure), a reactor core with lower core power and larger fractions of coolant volume within the reactor core. The EU website concludes that these features collectively increase significantly the time allowed for operators to react in case of incidents or accidents.

Nevertheless, some critics, such as the Union of Concerned Scientists (who I understand advocate against all new nuclear power development), argue that these passive systems (which, for example, might have less robust containment systems compared to full scale reactors) are not infallible, particularly during extreme weather events such as large earthquakes or major flooding or if the security applicable to SMRs is compromised. They also argue that the presence of multiple reactors at one site raises the risk of a cascading failure (i.e., an incident at one reactor damaging others on the same site) depending on location, as seen at Fukushima.

Given my understanding of the Darlington New Nuclear site, I would not expect major concerns related to extreme weather events, security and possible related cascading failure to be a significant area of focus for potential bond investors. All nuclear generation sites in Ontario host multiple reactors, and OPG has advised that all of them have a larger footprint than the Darlington New Nuclear site will have upon completion of the four SMRs. While potential bond investors will need to be satisfied that a comprehensive safety and security strategy is in place including quality assurance, regulatory oversight and emergency preparedness, I expect that, with appropriate education on these matters, the CNSC's established oversight and OPG and Ontario's many decades of experience with safely operating and refurbishing nuclear reactors will be sufficient for safety and security not, in and of itself, to be a barrier to accessing bond financing.

3. **Will potential bond investors accept the lack of diversification of revenue when only Unit 1 is in service?**

Initially, the SPV will operate a single SMR with no diversification of revenue. If the single asset experiences an unplanned outage, even temporarily, all revenue may be foregone for a period since revenue is based on production. Also, if unrecoverable operating costs are incurred, the impact of such costs on the SPV's cash flow will be higher than for a more diversified utility.

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.

I expect that it will take multiple bond issues and some years to achieve an optimal capital structure for the SPV. Until that happens, the expected cash generation should be high relative to the expected amount of debt service. The relatively low leverage after the first bond issue, combined with appropriately risk adjusted generation assumptions built into the early years' forecast (provided they are reflected in the regulated rates), would support the ability of Unit 1 to be out of service for a more significant period of time before payment of debt service is at risk.

While potential bond investors prefer a more diversified revenue stream, many individual non-diversified assets are financed on a non-recourse basis. In these cases, more careful attention is paid to both initial due diligence (e.g., reports from independent third parties, detailed financial forecasts, scenario analysis) and deal structuring (e.g., cash reserves, distribution tests). In addition, lack of diversification risk for the SMRs can be offset to a certain extent by ensuring that Unit 1 has a reasonable period of successful operation prior to any bond issuance. Other than waiting until additional SMRs are in service, this would be the most reassuring protection against lack of revenue diversification in these circumstances.

4. **Does the lack of a standalone legal entity for Unit 1 SMR create bond investor concerns?**

The SPV is being set up to construct and operate the four planned SMR units (including common infrastructure shared by all units). OPG currently expects that, subject to obtaining the requisite approvals, Units 2, 3 and 4 will be in various stages of development/construction at the in-service date of Unit 1, all within the same SPV. While the trust indenture will need to be designed to minimize the impact of risks associated with the development and construction of Units 2, 3 and 4 on the operating Unit 1, it is unlikely that such risks can be eliminated while using a single SPV.

As a result, absent arrangements to the contrary, there could be a risk that some cash proceeds from Unit 1 generation are diverted to fund the needs of other SMR units. An example might be a diversion of funds for safety reasons in response to demands of regulatory authorities. Also, any third-party liability associated with Units 2, 3 or 4 could impact on the ability to service the initial bonds. Similarly, the performance of Unit 2 and any bonds issued sometime after Unit 2 is in service could have an impact on the ability to pay debt service costs on the initial bond issue.

This cross-asset risk, both from a cash flow perspective and from a liability perspective, will need to be assessed, understood and managed to successfully issue bonds while some units are still under construction. I expect this issue will be an important consideration in negotiating the trust indenture (discussed below), as investors will seek sufficient assurance that they are not indirectly assuming construction risk. Overall, I believe this issue of multiple SMR units, with one operating and others under construction, will increase potential bond investors' aggregate risk assessment.

5. **Will regulatory risk be a significant concern to potential bond investors?**

In broad terms, regulatory risk considers the risk of actions by an economic regulator that could negatively affect the financial position of a regulated entity. There is always some degree of regulatory risk for a regulated entity but, in my experience, it is most relevant to equity investors (whose returns may be impacted by disallowed costs or reduced allowed returns, for example).

I note that bondholders do not bear the risk of disallowed costs relating to project construction. If certain construction costs are disallowed by the OEB, that will likely reduce the maximum amount of debt that can be issued after Unit 1 enters operation (due to a smaller rate base) but it should not, in and of itself, impact the ability to issue debt.

From a potential bond investor perspective, the OEB is an established regulator with an acceptable regulatory track record. By the time Unit 1 is in service, it is expected that the SPV will have undergone at least one rate proceeding (for the 2027-2031 rate term). Subject to any changes in the regulatory landscape between now and when Unit 1 is in service, I do not expect regulatory risk to be, in and of itself, a significant concern for bondholders.

6. Will there be concerns with Operator risk (i.e., OPG does not carry out its obligations under the various contracts with the SPV) that could deter a potential bond investor from participating in a bond issue?

As noted, the SPV is not intended to have any employees, with SMR operations fully contracted with OPG. I understand that the service contracts between OPG and SPV are a work in progress although I have reviewed a term sheet for the operating contract. These contracts will be subject to legal review by counsel for bond placement agents to ensure that the scope is appropriate.

I note that OPG has advised that they will not guarantee the performance of the SMRs to the SPV.

Once determined that the contracts are appropriate from bond investors' perspective (or amended if necessary), following due diligence, I do not expect potential bond investors to have material concerns about the ability of OPG to carry out its obligations under such contracts from a technical or organizational perspective. There are significant differences between CANDU technology and BWRX-300 technology, but Canada has an established nuclear industry and OPG has a lengthy satisfactory track record of operating nuclear facilities and has recently been managing major nuclear refurbishments. OPG will also have a majority equity investment in the SPV, which creates a significant incentive for optimizing performance.

Similarly, I do not expect potential bond investors to have material concerns about the ability of OPG to carry out its obligations from a financial perspective. OPG has two A3/A(l) credit ratings and one BBB+ rating, is wholly owned by the Province of Ontario and is a critical player in Ontario's energy industry.

7. **What are the key operating risks and are they likely to be acceptable to potential bond investors?**

There are numerous operational risks inherent in nuclear power generation that could lead to casualties, environmental damage, property damage and/or have a material economic cost. These include:

- Accidental radiation release from accidents
- Fuel defects
- Equipment failure
- Human error and improper maintenance
- External factors such as flooding, earthquakes, terrorist attacks
- Process-related issues (e.g., design flaws, software issues).

I reviewed OPG's granular assessment of operational phase risks for the SMRs. The outcome of many of these risks is an increased cost (extra employees, parts, time, etc.) that should not, unless truly material and non-recoverable, affect the timing of a first bond issue. Risks that do not result in production outages will be considered much lower risk by potential bond investors since as long as electricity is being produced, revenue will be received and the portion of revenue otherwise attributable to equity distributions (i.e., return on equity and return of equity) can instead be used to cover incremental operating costs without impacting the ability to service debt.

The biggest risks from a cash flow availability perspective are those risks that result in unplanned outages since no revenue is generated when the one and only unit is not operating, and such lost revenues are not recoverable through regulated rates. Examples of such risks could include maintenance strategies and fuel defects. There are also unknown risks that are, by definition, impossible to predict, both from an occurrence and impact perspective.

The first planned outage on Unit 1 is not expected to occur until after the first year of operation, meaning that information from refueling, maintenance and inspection will not likely be available if bond financing is undertaken prior to 12 months after the in-service date.

Practically, potential bond investors will not be in a position to fully consider all the risks associated with operating SMRs. However, they will perform the necessary due diligence to satisfy themselves that the risks are understood to the extent possible and are being effectively managed by the operator, OPG. They will likely require report(s) prepared by knowledgeable consultants to provide an independent opinion on the various operating risks and how such risks have been mitigated, particularly given that this will be the first SMR of its type anywhere in the world.

Finally, in the bond trust indenture, potential bond investors are likely to require the SPV to retain certain reserves to address expected/unexpected maintenance rather than distribute all excess cash to the owners.

I consider operating risk to be one of the bigger risks from a potential bond investor perspective because of the FOAK nuclear technology and the absence of an existing commercial fleet of SMRs operating anywhere in the world. While I consider some operating risks to be low (e.g., extreme weather events), others are very difficult to quantify (e.g., process-related and equipment failure) and I expect would be of concern to potential bond investors. The longer Unit 1 is in operation prior to the first debt issuance, the higher the level of comfort potential investors and credit rating agencies will have.

8. How will potential bond investors view fuel supply risk and reliance on foreign technology to enrich uranium?

Like most of the commercial nuclear power reactors in the world today, the required fuel supply for the BWR-300X SMRs is enriched uranium, which I understand Canada currently cannot supply. Uranium enrichment is a sensitive technology due to its potential use in nuclear weapons, which is why it is subject to strict international controls and monitoring.

In addition to general research, I held a detailed discussion with OPG regarding the fuel supply chain to assist me in determining whether the fuel supply chain, including reliance on foreign suppliers for enriching uranium, might be a significant factor in the availability of bond financing.

Unenriched uranium is natural uranium as it is found in the earth's crust. It is predominantly made up of U-238 (about 99.3%) and contains a small amount of U-235 (about 0.7%), which is the key fissile isotope needed for nuclear chain reactions. This natural form is used as the starting material for creating enriched uranium for nuclear fuel.

Uranium concentrate, commonly referred to as U_3O_8, is the product created when uranium ore has been mined, milled and chemically processed into a purer, more concentrated form of uranium than the ore it came from. The fine powder is packaged in steel drums and shipped to refineries for further processing. U_3O_8 is available from Canada, Kazakhstan, and Australia along with smaller amounts from some other non-Western countries.

OPG described four main steps in the fuel supply chain which I have summarized as follows:

- Procure U_3O_8 concentrates.
- Chemically convert the U_3O_8 concentrates into natural uranium hexafluoride ("UF_6"), a solid at room temperature.
- Heat the natural UF_6 into a gaseous state and pass it through a centrifuge cascade to create enriched UF_6 (with a higher percentage of U_{235}) and cool into a solid form in steel cylinders for transport.
- Convert the enriched UF_6 into UO_2 powder and then press into pellets, encase pellets in rods and assemble rods into fuel bundles.

OPG has multiple vendors of record (miners and traders) for the supply of U_3O_8. The responsibility for delivery of U_3O_8 concentrates to the conversion facility (step two) nominated by OPG lies with the vendor, not OPG.

For the first and second steps, OPG has signed two initial contracts that combine the purchase of concentrates and conversion to natural UF6. One contract is with Cameco in Canada, with conversion at Port Hope. The second contract is with Orano USA, LLC (Orano S.A.'s U.S. sales office); however, Orano S.A., a French based company, will be performing the UF6 conversion services at their French conversion facilities and Orano's mining and milling operating arm will supply the U3O8 component from Canada or other jurisdictions, all under the same contract. Conversion plants also operate in the U.S. and China. Future fuel procurements for the DNNP are expected to separate the purchase of concentrates (step 1) from the conversion process (step 2).

The third step involves the enrichment of natural UF6 to enriched UF6. The process of "enrichment" is used to increase the proportion of the fissile isotope, U_{235}, from the natural level of 0.7% to a higher level (e.g., 3-5% for nuclear power plants). For the DNNP, OPG has contracted Louisiana Energy Services ("LES"), a subsidiary of Urenco Group in New Mexico, U.S. to provide uranium enrichment. Urenco also provides enrichment services in Germany, Netherlands and the UK. OPG has also contracted with Orano USA, LLC; however, Orano S.A. will be performing the enrichment services at their French enrichment facility. Logistics and transport of enriched UF_6 from the suppliers (LES and Orano) to the fuel fabricator (see step 4 below) is the responsibility of the suppliers and the fuel fabricator, not OPG.

The fourth step involves converting enriched UF_6 by first heating it into a gas, then chemically converting it into uranium dioxide powder, which is pressed into ceramic nuclear fuel pellets that are baked at high temperatures and then loaded in metal tubes to form fuel rods, which are assembled into fuel bundles for use as nuclear fuel. For the DNNP, OPG has contracted with Global Nuclear Fuel Fabricators ("GNF") in Wilmington, N.C., U.S. for the fabrication of the fuel pellets, rods and bundles. GNF is a subsidiary of GE Vernova and a sister company of GE Hitachi, the supplier of BWRX-300 technology. The fuel bundles for the DNNP are of the GNF-2 fuel design. While the "nuclear design" of GNF-2 fuel bundles may differ from cycle to cycle on different BWR units, the "mechanical design" of GNF-2 fuel assemblies does not, and this GNF-2 fuel assembly mechanical design is deployed in other currently operating BWRs. While there are potentially other fuel bundle fabricators that could be considered for the DNNP, OPG advised that the process of design, testing, qualification, and licensing would be a multi-year undertaking.

Pursuant to a contract with OPG, GNF will deliver the fuel bundles to the DNNP site. There is a division of responsibilities, with OPG being responsible for certain matters such as the CNSC import licence and GNF being responsible for certain other matters.

Table I below summarizes the several initial contracts OPG has for the DNNP fuel supply and related services.

Table I		
DNNP Nuclear Fuel Supply Chain		
Supply Segment	Total Contracts	Non - U.S. Contracts
Uranium concentrates & UF_6 conversion services (procure concentrates and then chemically convert into natural UF_6)	2	2
Uranium Enrichment services (increase percentage of U_{235})	2	1
Fuel fabrication and technical services (conversion of enriched uranium into fuel bundles)	1	0

Having two or more contracts for fuel supply chain services in different jurisdictions reduces (but does not eliminate) geopolitical risk. Fuel costs represent a relatively small portion of overall cash operating costs and thus even high tariffs, if imposed, should not be a central concern for potential bond investors. Establishing fuel fabrication services outside the US would be a significant undertaking as part of the fuel supply chain.

The global geopolitical environment that exists following the in-service date of the first SMR unit could elevate or reduce potential bondholder concerns regarding the nuclear fuel supply chain. According to the World Nuclear Association, most of the about 500 commercial nuclear power reactors operating or under construction in the world today require enriched uranium for their fuel.

Potential bond investors will undertake due diligence, which could include an independent report, to satisfy themselves regarding fuel supply risk. While the nuclear fuel supply chain for the DNNP is more complex than for OPG's CANDU reactors, it does not appear to be particularly novel and OPG appears to have sought to diversify the supply chain to the extent commercially reasonable. Given that the enriched uranium nuclear fuel for the BWRX-300 SMRs is the same as is widely used in most reactors around the world, I believe the consideration of this risk by potential bond investors can be managed, absent changes in the geopolitical environment.

I have sought to determine if there are any obvious concerns in the fuel supply chain that might prevent potential bondholders from participating in a bond offering and none are currently apparent to me, absent changes in geopolitical risk.

9. **How might general (non-fuel) supply chain and geopolitical risk affect potential bond investors' interest in financing the SPV?**

OPG indicated that the SMRs utilize supplies that are sourced globally as illustrated in Table II.

Table II		
DNNP Global Supply Chain		
Region of Supply	% of Supply Chain Value	Number of Suppliers
Canada	48%	90 (89 in Ontario)
USA	10%	11
Italy / France / Germany / Spain	17%	4
Japan	6%	1
TBD (Europe or N.A.)	19%	TBD

OPG indicated that most of the contracts were competitively bid but there were some single-sourced contracts with foreign suppliers. An example would be the heat exchanger and steam turbine generator that are being sourced in France from a supplier that has supported BWR units in the past. There are also some single-sourced contracts from U.S. based suppliers for specific BWR components such as nuclear quality assurance parts.

While the projected in-service date of Unit 1 is still five years away, OPG has been developing the post-construction supply chain for the SMRs and working with foreign suppliers to expand the availability of spare parts and supplies made in Canada, where possible.

At the time of the first potential bond financing, Unit 1 will be completed and in-service. Therefore, the country of origin of installed equipment matters to the extent that replacement parts or supplies or intellectual property are required to operate and maintain the SMR.

OPG has purchase options for various types of equipment and supplies for Units 2, 3 and 4 plus spares. These purchase options could be diverted to Unit 1 if necessary to keep Unit 1 properly maintained and in operation.

The contract with GE Hitachi for the first SMR unit covers a range of activities including design, engineering, licensing support, and training, with ongoing support services planned through a dedicated engineering and service center located in Ontario, in proximity to the DNNP site.

While OPG does not have at least two suppliers in different countries for every part of the SMR, the procurement strategy being implemented causes me to believe that the overall supply chain risk for an in-service SMR is likely to be acceptable from a potential bondholder’s perspective, absent material changes in geopolitical risk.

10. **Given that OPG is responsible for decommissioning risk, would there be any outstanding concerns by institutional investors?**

Pursuant to the expected lease between OPG and the SPV, OPG will be responsible for decommissioning the SMRs and managing spent fuel and nuclear waste (both during and after in-service operations). Given that this risk is borne by OPG (and not SPV) and that decommissioning is expected to be decades after the maturity of the first bond issue, this risk should not be a factor in potential bond investors’ willingness to lend to the SPV.

PART III – Bond Related Considerations

In addition to SMR specific risks, investors will consider a variety of factors not specifically related to the assets but to the actual bond offering itself, in assessing whether to lend to the SPV, some of which are addressed below.

1. What is a trust indenture and what is the process and timeline to put it in place?

A trust indenture, sometimes referred to as a borrowing platform, sets out the terms and conditions of the current and all future bond issuances by a particular entity. It must be very carefully put together because once a single bond has been issued, it can be very difficult to change.

The trust indenture will set out key covenants, including financial covenants, that the borrower must meet. It will also set out representations and warranties, security and events of default. It must be forward-looking to address various future scenarios such as the completion of Units 2, 3 and 4 as well as other matters that could come up such as changes to key contracts or future changes in ownership.

In my experience, a trust indenture for a complex project/asset can take many months to negotiate. While the trust indenture could be worked on contemporaneously with commissioning activities, it is reasonable to expect that it will not be completed until sometime well after the in-service date once investment dealers, independent engineers and legal counsel have observed the asset in operation. Even if the trust indenture could be finalized earlier, it could be sub-optimal for the SPV to finalize a trust indenture (that could exist for some 60 years) too early after the in-service date, as unnecessarily stringent or costly terms and conditions could be embedded for the life of the asset.

The SPV's objective will be to negotiate a trust indenture with as few constraints as possible, while attracting successful financing. Bond agents (investment dealers) will want to have sufficient covenants, cash waterfalls, cash reserves and other mechanisms to ensure that bondholders are sufficiently protected from unanticipated future changes, and to make the bonds more marketable. 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 in-service 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.

2. **What is the process for obtaining credit ratings and how many credit ratings would likely be required?**

The SPV will need to obtain credit ratings prior to issuing bonds. Based on precedents and given the FOAK nature of the SMR asset, and the likely size of the borrowing program, two credit ratings will be required/expected. This process of obtaining credit ratings is time-intensive, as the credit rating agencies will perform a detailed review of all relevant aspects of the SMR program and the debt issuance program. Some of this work (related to technology, supply chain, etc.) could be done in advance of the in-service date of Unit 1 and some likely cannot (e.g., details of bond offering and trust indenture, completion of any independent reports). While the credit rating agencies will have experience with CANDU technology, they most likely will not have sufficient experience with the latest generation of BWR SMR technology, given that OPG is expected to be the first generator in the G7 to commission a BWRX-300 reactor.

In my experience, there are several months of information requests, discussion and analysis before a credit rating is obtained for an issuer like the SPV. Typically, information related to the trust indenture is not shared with the credit rating agencies until it is close to final (otherwise it makes changes more difficult to make). Completion of independent reports, which the credit rating agencies will need to review, is also likely to extend past the in-service date.

Furthermore, it is likely sub-optimal for the SPV to obtain credit ratings too early after the in-service date of the first SMR unit, since the credit rating agencies will err on the side of conservatism if there is very little operating history. A lower credit rating would increase the cost of financing and could also narrow the potential investor base for the bonds as institutional investors, such as large insurance companies, or bond fund managers may want to limit the number of bonds in lower credit rating categories and often have a minimum credit rating level embedded in their investment policies. Beyond the impact on the initial issuances, these considerations are important as the initial bond issuance could influence the benchmark spread for the SPV's subsequent issuance(s).

The lowest investment grade credit rating is BBB (low) or equivalent. Based on my experience in arranging bond issuances for first-time and infrastructure-related issuers, the SPV would likely be focused on achieving a BBB (mid) rating to facilitate a larger, more broadly based bond issuance program, which could be challenging to achieve at or near the in-service date. For comparison purposes, Bruce Power LP has a BBB+ (stable trend) rating from Fitch, a BBB (positive trend) rating from DBRS Morningstar and a Baa2 (stable trend) rating from Moody's. Bruce Power LP has the benefit of a long history of operations, proven technology, and diversification (several reactors at two different sites).

While there are many unknowns at this time, I expect that the SPV is likely to need at least some reasonable period of satisfactory operating history after the in-service date to obtain two investment grade credit ratings.

3. **Can you comment on the Risk/Reward Profile of Unit 1 for potential bond investors?**

Based on information provided by investment banks, there are about 50 utilities / infrastructure / energy infrastructure / power generation bond issuers in Canada with broadly marketed investment grade bonds outstanding, where credit spreads are regularly tracked and broadly communicated to investors. The highest and lowest credit spreads for these bond issuers as of mid-October 2025 were approximately as set out in Table III.

Table III			
Canadian Investment Grade Utility Issuers (~50 issuers)			
Credit Spread ("CS")	**5-year**	**10-year**	**30-year**
Lowest CS -- A/A+	55 bps	80 bps	105 bps
Highest CS -- BBB(l)	122 bps	170 bps	225 bps
OPG CS -- A(l)/A3/BBB+	65-75 bps	100 -110 bps	125-130 bps

The difference in credit spread between an OPG bond and the highest credit spread investment grade bond in the above sample is approximately 55 bps (5 years) and approximately 65 bps (10 years). Assuming the SPV's 10-year debt (the longest maturity most likely available in an initial offering) is priced with a spread 20% higher than the highest spread from the ~50 issuers included in the table above, the incentive for debt investors is at most ~1% per annum relative to buying OPG bonds. This is arguably the potential upside for an investor purchasing the SPV's 10-year bonds. 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.

4. **What is involved in marketing a Bond issue for Unit 1 and how long would it take for the marketing process?**

Preparation for marketing an inaugural bond offering for a newly established entity without an established operating and financial history is a time-intensive exercise. Some of the most time intensive activities include:

- Preparation of a detailed and comprehensive offering memorandum describing the SPV, the asset, regulation, key risks, financial forecasts, the trust indenture (covenants, events of default, security, etc.), legal matters and more.
- Preparation of independent reports to the extent deemed necessary (e.g., insurance report, technical report).
- Obtaining finalized credit rating reports.

Once preparation is complete, a key objective would be to educate the investor base and obtain a sufficiently broad range of investors willing to purchase bonds at a reasonable rate/spread. 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.

Once all the preparatory work is completed, the actual investor meetings and “roadshow” for a first time SMR issuer might only take a few weeks.

5. **How long would the entire bond issuance process likely take?**

Every project and inaugural bond issue is different. However, for a FOAK nuclear project first time bond issue, I would expect that preparation for and marketing of a bond offering would take at least 6-9 months from the in-service date. If any independent reports are required from third parties, they would likely be asked to start their work prior to the in-service date so not to unnecessarily delay the process.

This estimated minimum 6–9-month period is the actual time to obtain credit ratings, negotiate documentation, market and issue a bond but does not incorporate the longer period that is very likely required to observe Unit 1 in operation to partially mitigate 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, as previously discussed.

G. Conclusion

In my opinion, having explored the key risks summarized above, potential bond investors will view FOAK nuclear technology risk as the biggest unknown and unquantifiable risk. Integral to the FOAK nuclear risk is operating risk in the form of unexpected events after the in-service date, particularly insofar as they may affect output from the facility. These two key risks will be exacerbated by the absence of an operating record for a BWRX-300 reactor anywhere in the world.[1] I expect that the limited spread upside for a bondholder relative to risk and the unquantifiable magnitude of these FOAK risks will make if very challenging to issue non-recourse investment grade bonds within 12-18 months of the in-service date of Unit 1.

Having a reasonable operating period after the in-service date is, I believe, critical for a successful first bond offering. This initial operating period may also be necessary to obtain even the lowest investment grade credit ratings. An initial operating period prior to the first bond offering will allow OPG, on behalf of the SPV, to identify and, if necessary, work through risks and issues in the first year, plan for integration of the second unit and address items that may be outstanding on the in-service date. At the same time, it will give credit rating agencies and potential bond investors the opportunity to evaluate the initial period of Unit 1 operations, which could ultimately result in a less restrictive trust indenture, and should result in lower cost bond offerings and, potentially, a benefit to ratepayers.

While any one risk may not on its own detract from potential bond investors' willingness to invest in the SPV, risks are not viewed in isolation and multiple risks can result in an aggregate risk profile that is more challenging than any single risk. For example, in addition to addressing various risks related to

Unit 1 on its own, it will be important to determine the extent to which financing can be structured to address the risk to initial bond investors from the simultaneous construction of Units 2, 3 and 4 within the SPV and the potential spillover of construction risk (diversion of cashflow or risk of liabilities). While this risk factor will reduce as subsequent units are successfully completed and brought online, it will be a key area of focus for the inaugural bond issue.

The SPV will want a successful first issue that attracts the interest of a sufficiently broad range of institutional investors to set the tone for future issuances. At a minimum, this will require careful structuring of the trust indenture, extensive investor education (including a detailed offering memorandum and investor meetings) and supportive credit ratings/reports. In my experience, for a new entity such as the SPV, these requirements will likely take at least 6-9 months to complete, only some of which are likely to be optimally undertaken prior to the in-service date. There may also be strategic reasons for the SPV to defer the initial offering to provide more operational history to potentially obtain more favourable trust indenture terms.

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.

This concludes my evidence.

EXHIBIT A

CURRICULUM VITAE

CLIFF INSKIP

CLIFF INSKIP, CFA, FRM, P.ENG, RPA, C.DIR., A.C.C.

PROFESSIONAL PROFILE

Experienced Board Chair, Committee Chair and Board Director. Extensive board experience in the regulated financial services sector including boards of a pension plan, a life insurer and a bank subsidiary in London, England as well as experience on the board of an electrical distribution utility and an electrical power generation company.

Experienced Trustee including ONE-T Benefits Trust for 17,000 education sector employees in Ontario and Kerr Street Mission Foundation and Soar Like an Eagle Foundation (charitable foundations)

Seasoned financial executive: investment banker, domestic and international lender, financial advisor to corporations and governments, bond underwriter, corporate and project finance advisor. Extensive experience advising on, evaluating, negotiating, and financing large, complex projects in multi-stakeholder environments for major North American companies. Experience with infrastructure, renewable energy, real estate, and private equity acquisitions and valuations. Extensive international work experience.

Advised ~20 Boards of Directors or Finance Committees.

Chair of Awards Committee for Canadian Council for Public Private Partnerships (2012-2021).

DIRECTORSHIPS, TRUSTEESHIPS & BOARD COMMITTEES

Business Boards & Trusts (current roles shown in **bold)**

- **OMERS Administration Corporation** (pension plan)
  - Director (2015 - present)
  - Member of Investment Committee (2015 - present)
  - Member of Audit & Actuarial Committee (2015 - 2022)
  - Member of Risk Oversight (2017-2020) & Governance & Risk Committees (2023 - present)
- **Serenia Life Financial** (fraternal life insurance)
  - Chair of the Board (2020 – 2022) and Director (2016 - present)
  - Vice Chair (2019-2020)
  - Chair of HR & Governance Committee (2024-present) and member Audit Comm. (2017-2020)
  - Chair of CEO Search Committee (2018)
  - Member of Investment Committee and Risk & Compliance Committee (2022 – 2024)
- **Ontario Non-Union Education Trust** (ONE-T) (education sector life & health benefits trust)
  - Chair of the Board of Trustees (2021 – present)
  - Member of Audit, Finance & Investment Committee; Benefits & Communications Committee and Governance Committee (2021 – present)
- JCM Power Corporation (international renewable power developer/producer)
  - Director (2015 - 2022)
  - Chair of Audit Committee (2016 - 2022)
  - Member of Compensation Committee (2020 - 2022)
  - Member of Governance Committee (2016-2020)
- Oakville Enterprises Corp. / Oakville Hydro (distribution utility, renewable power, construction)
  - Director (2013-2020)
  - Chair, Finance & Audit Committee (2018-2020)
  - Member of Governance & Risk, Human Resources and Advisory & Nominations Committees
- CIBC World Markets plc (regulated bank subsidiary in the UK, formerly CIBC Bank plc)
  - Director (1992 -1995)

Charitable Boards and Foundations (current roles shown in **bold)**

- **Kerr Street Mission Foundation**
  - Inaugural Board Chair (2023-present)
- Kerr Street Community Services / Kerr Street Mission (social services charity)
  - Board Chair (2017 - 2021) and Director (2015 - 2024)
  - Chair of Governance & Nominations Committee (2017 - 2024)
  - Chair of Fundraising & Stewardship Committee (2018-2019)
- BetterPlace International (US based charity; hospital development in Africa)
  - Director (2017-2020)
- **Soar Like an Eagle Foundation** (private charitable foundation)
  - Founder, Executive Director, and Trustee (2012 - present)

WORK HISTORY

PRESIDENT, POLAR STAR ADVISORY SERVICES INC. (PART-TIME) *2015 – PRESENT*

- Provide independent consulting advice on financing strategies, risk management and transaction assessment for major projects (>$1bn) including port, public transit, highway and power generation and transmission sectors. Expert witness engagements.

MANAGING DIRECTOR, HEAD OF INFRASTRUCTURE & PROJECT FINANCE, DCM, CIBC *2010-2014*
MANAGING DIRECTOR, DEBT CAPITAL MARKETS (DCM) – CIBC *1997-2009*
VICE PRESIDENT – CIBC WOOD GUNDY SECURITIES INC. *1995-1996*

- Established, built, and led CIBC's very successful infrastructure advisory and bond underwriting business. Extensive experience with public/private bond markets, institutional investors, and credit rating agencies.
- Member of New Products Committee: assessed risks/opportunities of new trading room products.
- Advisor to public entities such as Port Metro Vancouver, five Airport Authorities, Province of B.C., Province of Alberta, Transport Canada, Calgary Health Region, City of Winnipeg, Canadian Blood Services, BC Transit, BC Ferries & York Region on financing, P3 and/or strategic option assignments.
- Advisor on a wide range of renewable/non-renewable and mid-stream energy projects involving clients such as Brookfield Power, Northland Power, Spectra Energy, OPG, Columbia Power and CNRL.
- Advised private sector proponents or government procurement agencies on large, complex P3 projects including highways, bridges, bundled schools, office buildings, water projects and a hospital.
- Notable advisory and financing assignments include:
  - Jointly advised and led the bond financing for a $9.7 billion multi-stakeholder refinery project in Alberta - the largest project financing in Canadian history according to Bloomberg.
  - Advisor and Joint Lead Bond Agent on a $2.6 billion power project that was awarded the Grand Pinnacle Prize for financial innovation (first Canadian winner).

DEPUTY MANAGING DIRECTOR – CIBC WORLD MARKETS PLC *1992 – 1995*
GENERAL MANAGER, EUROPE – CIBC *1991 – 1992*

- CIBC World Markets plc (previously CIBC Bank plc) was a new regulated bank in the UK.
- Headed a UK based team responsible for corporate, leveraged and mezzanine lending businesses.
- Worked with the CEOs of CIBC's subsidiaries in UK, Germany, France and Italy and advised on matters such as new business initiatives, management of distressed portfolios and recapitalization of subsidiaries.

ASSISTANT GENERAL MANAGER, TRADE FINANCE – CIBC *1985 – 1990*

SENIOR EXPORT FINANCING OFFICER (Final Position) – EDC (Ottawa) *1980 – 1985*

EDUCATION

- University of British Columbia
  - MBA (finance and international business)
  - B.A.Sc. (civil engineering)
- International Banking Summer School Program (Cambridge University)
- Harvard Summer School (Corporate Governance 2019; Private Equity 2021)
- University of Toronto Rotman - ICPM Board Effectiveness Program

PROFESSIONAL DESIGNATIONS

- McMaster University / Director's College
  - Chartered Director (C. Dir.)
  - Audit Committee Certified (A.C.C.)
- Professional Engineers Ontario
  - Professional Engineer (P.Eng.)
- CFA Institute
  - CFA Charterholder
- Global Association of Risk Professionals
  - Certified Financial Risk Manager (FRM)
- Canadian Securities Institute
  - Fellow of Canadian Securities Institute (FCSI - retired)
- Association of Corporate Treasurers, UK
  - Fellow of Corporate Treasurers (FCT - retired)
- Dalhousie University/Int'l Foundation of Employee Benefit Plans
  - Retirement Plans Associate (RPA)

PROFESSIONAL ASSOCIATION MEMBERSHIPS

- Professional Engineers Ontario
- CFA Institute
- Institute of Corporate Directors

AWARDS

- Recipient of the TopGun Banker designation by Brendan Woods recognizing the highest achievers in the investment banking industry.

EXPERT WITNESS ENGAGEMENTS

- National Energy Board
- Standing Senate Committee on National Finance
- Ontario Superior Court of Justice, Commercial List
- Nova Scotia Utilities Review Board
- Nova Scotia Energy Board

SPEAKING ENGAGEMENTS

Euromoney, Insight, National Post, Alberta Economic Summit, Association of Municipal Treasurers, Premier's Infrastructure Summit (Ontario), Canadian Airports Council, Canadian Council for Public Private Partnerships, Pan-Pacific Quantity Surveyors Association, North American Strategic Infrastructure Leadership Forum, Canadian Construction Association, Canadian Solar Industries Association, Energy Council of Canada, Ontario School Boards Financing Symposium, University of Toronto, York University, UBC.

EXHIBIT B
Materials Relied Upon

Materials Relied Upon are set out below:

a) GE-Hitachi website
   https://www.gevernova.com/nuclear#hash2
b) World Nuclear Association website
   https://world-nuclear.org/
c) IAEA Website (background information)
   https://www.iaea.org/newscenter/news/what-are-small-modular-reactors-smrs
d) World Nuclear News Website May 23, 2025 Canada's First SMR Project
   https://www.world-nuclear-news.org/articles/what-is-the-budget-for-canadas-first-smr-project
e) Government of Canada website: Darlington New Nuclear Project
f) DBRS Morningstar credit rating reports (April 11, 2025 OPG rating press release, April 21, 2025, OPG credit rating report, and June 3, 2025 commentary)
g) Moody's OPG credit rating reports (May 20, 2025, and June 26 & 30, 2025, reports)
h) S&P Report dated April 14, 2025
i) Various OPG press releases involving DNNP and articles about SMRs
j) PowerPoint presentation (4 pages) from OPG on BWR history and FOAK Equipment
k) Document from OPG titled New Nuclear Operations Phase Risks
l) Document from OPG titled DNNP Overview – Project and Operations (October 15, 2005)
m) Document from OPG titled DNNP Overview – SPV and Regulatory Structures (October 10, 2005)
n) Document from OPG titled DNNP (provides very high-level overview)
o) Document from OPG titled DNNP Global Supply Chain
p) Various Indicative Credit Spread documents from Canadian investment dealers

q) Indicative Term Sheet for management, operation, maintenance and administrative services to SPV.

r) OEB Decisions:

i. EB-2016-0152 (OPG's application for 2017-2021 nuclear rates)
https://www.rds.oeb.ca/CMWebDrawer/Record/595053/File/document?_gl=1*1lwon4r*_gcl_au*NTM5MjY3NTcuMTc1ODg1OTgyOA..

ii. EB-2020-0290 (OPG's application for 2022-2026 nuclear rates)
https://www.rds.oeb.ca/CMWebDrawer/Record/732079/File/document?_gl=1*17ntqpo*_gcl_au*NTM5MjY3NTcuMTc1ODg1OTgyOA..

iii. EB-2024-0063 (OEB Generic Cost of Capital Hearing)
https://www.rds.oeb.ca/CMWebDrawer/Record/893627/File/document?_gl=1*4o4g4e*_gcl_au*NTM5MjY3NTcuMTc1ODg1OTgyOA..

EXHIBIT C
BWR Technology

Boiling Water Reactor (BWR) technology is a mature technology, originated in the 1950s and developed over more than 60 years. The first BWR plant to generate electricity for a utility grid began operating in 1957.

Key milestones in BWR history

- **1950s: Origins and early prototypes**
  - **1954:** The Experimental Boiling Water Reactor (EBWR) was constructed at Argonne National Laboratory in Illinois.
  - **1957:** The Vallecitos Boiling Water Reactor (VBWR), built by General Electric, became the first privately owned and operated nuclear plant to deliver electricity to a public utility grid.
- **1960s: Commercialization (Generation I)**
  - **1960:** The first large-scale commercial BWR, Dresden 1, was commissioned by General Electric in Illinois.
  - **1969:** The BWR/2, which featured a direct cycle and internal steam separation, began operating at Oyster Creek in New Jersey. This and subsequent 1970s designs are often called Generation II reactors.
- **1970s and beyond: Further development (Generation II)**
  - Throughout the 1970s and 1980s, BWR designs continued to evolve, with improvements made to increase power output and enhance safety features.
  - More than 60 GE BWRs were put into operation during this period, with thousands of cumulative years of operational experience.
- **1990s: Advanced designs (Generation III)**
  - **1996:** The first Generation III Advanced Boiling Water Reactor (ABWR) began commercial operation in Japan at the Kashiwazaki-Kariwa Nuclear Power Station.
- **2000s and today: Simplified designs (Generation III+)**
  - **2014:** GE-Hitachi's Economic Simplified Boiling Water Reactor (ESBWR), a Generation III+ reactor with advanced passive safety systems, was certified by the U.S. Nuclear Regulatory Commission but not built. The ESBWR builds on concepts from the earlier Simplified Boiling Water Reactor (SBWR) design which was approved in 2014 but also not built.

EXHIBIT D
Features of an SMR

Source: https://www.twi-global.com/technical-knowledge/faqs/small-modular-reactor

"The World Nuclear Association lists the features of an SMR, including:

- Small power and compact architecture and usually (at least for nuclear steam supply system and associated safety systems) employment of passive concepts. Therefore, there is less reliance on active safety systems and additional pumps, as well as AC power for accident mitigation.
- The compact architecture enables modularity of fabrication (in-factory), which can also facilitate implementation of higher quality standards.
- Lower power leading to reduction of the source term as well as smaller radioactive inventory in a reactor (smaller reactors).
- Potential for sub-grade (underground or underwater) location of the reactor unit providing more protection from natural (*e.g.* seismic or tsunami according to the location) or man-made (*e.g.* aircraft impact) hazards.
- The modular design and small size lend itself to having multiple units on the same site.
- Lower requirement for access to cooling water – therefore suitable for remote regions and for specific applications such as mining or desalination.
- Ability to remove reactor module or in-situ decommissioning at the end of the lifetime.

Generally, modern small reactors for power generation, and especially SMRs, are expected to have greater simplicity of design, economy of series production largely in factories, short construction times, and reduced siting costs. Most are also designed for a high level of passive or inherent safety in the event of malfunction. A 2010 report by a special committee convened by the American Nuclear Society showed that many safety provisions necessary, or at least prudent, in large reactors are not necessary in the small designs forthcoming. This is largely due to their higher surface area to volume (and core heat) ratio compared with large units. It means that a lot of the engineering for safety including heat removal in large reactors is not needed in the small reactors."

Polar Star
Advisory Services

October 1, 2025

Ontario Power Generation Inc.
700 University Avenue
Toronto, Ontario
M5G 1X6

Attention: Peter Cuff

Dear Sir:

Polar Star Advisory Services Inc. (the "Consultant", "we" or "us") understands that Ontario Power Generation Inc. (the "Company", "OPG" or "you") wishes to retain the Consultant to act as a finance expert in connection with an application to the Ontario Energy Board ("OEB" or "Board") for payment amounts in respect of the Darlington New Nuclear Project (the "Application") relating to a project to develop, construct and operate small modular reactor units at the Company's Darlington site (the "Project"). This retainer is being executed on behalf of the Company by Peter Cuff, an employee in the Company's Law Division ("Law Division"), and is being entered into for the purpose of assisting the Law Division to assess legal risks associated with the Project and with providing legal advice to other parties within OPG.

By your acceptance of this letter (the "Agreement"), you appoint the Consultant, and we agree to provide the Services (as defined below) on the terms and subject to the conditions set out below.

Instructions in respect of the Consultant's responsibilities described below, and any waivers or approvals contemplated herein will come from legal counsel at the Law Division of the Company.

1. **Responsibilities.** The Services will involve:

(a) Assessing the Project's prospects for securing non-recourse investment grade project financing, for the first 12-18 months following the commercial in-service date of the first unit taking into account as appropriate relevant considerations including the nature and timing of the project and assuming an equity-partnership ownership structure.

(b) discussing the findings and preliminary results of the assessment with Law Division on a date to be agreed upon (the "Discussion of Findings"), which shall be no later than the later of (i) 23 days after receipt by the Consultant of a Project description (the "Project Description") which is the basis for the Consultant's assessment; and (ii) October 24, 2025, unless otherwise agreed to by the parties;

(c) if requested by Law Division, producing a written report detailing the Consultant's assessment, findings and conclusions (the "Report"), which (i) shall be delivered to OPG no later than the later of 30 days after receipt by the Consultant of the Project Description and October 31, 2025 for the draft Report and no later than the later of 37 days after receipt by the Consultant of the Project Description and November 7, 2025 for the final Report, unless otherwise agreed to by the parties and (ii) may be filed by OPG with the Board in connection with the Application;

(d) if requested by Law Division, providing support during the hearing of the Application in connection with the scope of the services provided hereunder ("Application Support Services"), which may include (to the extent requested):

(i) assistance in responding to interrogatories applicable to the Report;

(ii) appearance at a technical conference to respond to oral questions on the Report;

(iii) testifying about the Report as an expert witness either orally or in writing; and

(iv) assisting in responding to undertakings (i.e., written questions during a hearing) on the Report;

and such other matters as the parties may agree from time to time (collectively, including Application Support Services, Discussion of Findings and the Report, the "Services"). The Consultant will not be obligated to provide any services that it determines, in its unfettered discretion, (i) it is not qualified or does not have the capacity to provide, or (ii) could create a conflict or potential conflict. The Consultant's responsibilities will be performed by an individual or individuals provided by the Consultant who is/are approved by the Company, in its unfettered discretion, in writing in advance. For the avoidance of doubt, as of the date of this Agreement, Cliff Inskip is the only person that the Company confirms as approved.

2. **Provision, Accuracy and Use of Information.** The Company agrees to provide the Consultant with all information reasonably necessary to provide the Services. In carrying out our responsibilities hereunder, we will necessarily rely on such information prepared or supplied by you and we assume no obligation to verify the accuracy or completeness of such information and under no circumstances will we be liable to you or any third party for any damages arising out of the inaccuracy or incompleteness of such information. Unless advised otherwise, we will be entitled to assume that there has been no material change in such information and will be entitled to rely thereon.

3. **Conflicts.** The Consultant is not aware of any conflicts of interest and agrees that it will promptly advise the Company upon becoming aware of any actual or potential conflict of interest related to the Services. The Company agrees to notify the Consultant promptly of any actual or potential conflict affecting the provision of the Services of which it becomes aware.

[redacted]

[redacted]

5. **Fees.** In consideration of our acceptance of this Agreement and the provision of the Services, you will pay us the greater of (i) [redacted] (the "Minimum Fee") and (ii) [redacted] per hour (the "Advisory Rate") for each hour worked by Cliff Inskip plus, in each case, any applicable sales, goods and services or value added taxes. If the Company requests Cliff Inskip to attend meetings and/or otherwise work at a location specified by the Company which is more than an hour from where Cliff Inskip is physically located (a "Travel Location"):

- on such days where meetings are attended and/or work is undertaken at the Travel Location, you agree to pay the greater of (i) a daily amount of [redacted] and (ii) the product of the Advisory Rate and the actual number of hours worked on such day (provided that the Consultant commits to work at least 3 hours on such day and the Company agrees to avoid scheduling constraints or lack of work constraints that would impede the Consultant's ability to meet such commitment) plus, in each case, any applicable sales, goods and services or value added taxes; and
- on such days which are air flight travel days and no meetings are attended, you agree to pay the greater of (i) an amount of [redacted] and (ii) the product of the Advisory Rate and the actual number of hours worked on such day plus, in each case, any applicable sales, goods and services or value added taxes. The Consultant agrees that wherever reasonably possible, Consultant shall coordinate with the Company to plan air flight travel days on days when meetings are attended or shall otherwise make reasonable best efforts to work a minimum of 2 hours on such air flight travel days, provided there is work available to be done.

In the event that the Company approves in writing any other individual(s) pursuant to Section 1 of this Agreement, the Company agrees to pay such fees as it may agree in writing for such other individual(s) provided by the Consultant and approved by the Company in writing in advance. The Consultant agrees to send the Company a quarterly invoice setting out the aggregate fee (the "Advisory Fee") and a brief description of Services provided (commencing with the period ending December 31, 2025 and the Company agrees to pay such Advisory Fee by electronic or wire transfer within 45 days of receipt of an invoice unless the Company provides notice to the Consultant that it is disputing the amount of such invoice. In such case, the Company shall pay the undisputed amount but shall be entitled to withhold the disputed amount until the dispute is resolved between the parties, at which time the Company shall only be required to pay the portion of the disputed amount the parties have agreed upon or the amounts otherwise determined as payable. The Consultant represents that it is registered for the Goods and Services Tax ("GST") and its registration number is 83314 5394 RT0001.

6. **Expenses and Taxes.** The Company shall reimburse the Consultant for all actual, reasonable business expenses properly incurred relating to the provision of the Services including travel expenses plus, in each case, any applicable sales, goods and services or value added taxes. Aggregate expenses in excess of C$2,000.00 in any calendar quarter, excluding expenses related to travel specifically requested by the Company, shall be subject to the prior written approval of the Company. Amounts payable to the

Consultant hereunder shall be payable within 45 days of submission of an invoice and reasonable supporting documentation to the Company.

7. **Use of the Consultant's Advice and Opinions.** The Company and the Consultant expressly agree that if the Consultant provides advice and/or recommendations to the Company, all decisions in connection with the implementation of such advice and recommendations shall be the sole responsibility of, and be made by, the Company. The Company agrees that any opinions provided by the Consultant in its capacity as a project finance expert hereunder are (i) for its and/or its affiliates internal purposes and/or (ii) for submission in connection with proceedings before the Board only and, without the prior written consent of the Consultant, will not be referred to in any offering or other document provided to third parties.

8. **Term.** Notwithstanding the formal date of this Agreement, this Agreement shall be effective as of October 1, 2025, and shall continue unless terminated by either you or us upon thirty (30) days prior written notice. However, the obligations pursuant to paragraphs 4, 5, 6, 7, 8, 10, 11, 12, 13, 14, 15 and 17 hereof will survive the completion of our engagement hereunder or the termination or purported termination of this Agreement. Upon termination the Company will promptly pay to the Consultant all fees, expenses and taxes in respect of Services provided up to the effective date of termination together with applicable taxes.

9. **Compliance with Laws.** The parties will comply with all applicable laws and regulations applicable to the subject matter of this Agreement.

10. **Confidentiality and Privilege.** Except as otherwise permitted herein, all work performed by the Consultant in connection with this Agreement, including all findings, opinions and conclusions the Consultant reaches in relation to this Agreement, and any communications relating thereto, are strictly privileged and confidential and shall not be disclosed to any other person or party without the prior written consent of the Company. The Consultant agrees to designate all written communications and material expressing findings, opinions or conclusions accordingly. The Consultant further agrees to notify the Company in the event that the Consultant receives a request to disclose information relating to this matter, and agrees to cooperate with the Company, to the fullest extent permitted by law, to prevent or limit the disclosure of such material or otherwise preserve the privileged and confidential status of such material.

To the extent that, in connection with the provision of Services hereunder, the Consultant comes into possession of confidential or proprietary information of or supplied by the Company or its affiliates ("Confidential Information"), the Consultant will not disclose, and will ensure that the Consultant's Representatives will not disclose, such information to any third party without the Company's prior written consent, except (i) as may be required by law, regulation, judicial or administrative process, (ii) to the Consultant's legal, tax and accounting advisors provided such advisors are subject to professional or contractual obligations of confidentiality, (iii) in connection with litigation pertaining thereto, or (iv) to the extent the Consultant must disclose, or determines in good faith it should disclose, to third parties that the Consultant is or was an advisor to the Company in order to satisfy professional standards arising due to the need to disclose a potential conflict of interest; provided that, the Consultant may disclose to third parties the fact that the Consultant is or was an advisor to the Company in the event the Consultant's engagement becomes a matter of public record in connection with regulatory or like proceedings. Confidential Information shall not include information which:

- shall have otherwise become publicly available (including, without limitation, any information filed with any governmental agency and available to the public) other than as the result of a disclosure by the Consultant in breach hereof;

- is disclosed by the Company to a third party without substantially the same restrictions as set forth herein;

- is disclosed in good faith to the Consultant by a third party (who is not disclosing the same on behalf of the Company) having, to the best knowledge and belief of the Consultant following due enquiry, legitimate possession and the right to make such disclosure without passing on or violating any obligation of confidence;

- is known by the Consultant prior to its receipt from the Company without any obligation of confidentiality with respect thereto; or

- is developed by the Consultant independently of any disclosures made by the Company to the Consultant of such information.

11. **Intellectual Property.** For the purposes of this Agreement, "Contract Property" means all trade secrets, trademarks, patents, copyrights, and other proprietary rights of the Company and its affiliates, together with all documents, reports, information, data, or products developed, improved or prepared by the Consultant while performing this Agreement, excluding any Consultant Property (as defined below). All Contract Property will be and will remain the sole property of the Company or its affiliates and will be delivered to the Company upon termination of this Agreement or upon demand by the Company, provided that the Company grants to the Consultant a perpetual, non-exclusive, royalty-free license to use and reproduce the Contract Property developed, improved or prepared by the Consultant, including the right to sublicense those rights, provided that the Consultant may not use or exploit any Confidential Information of the Company which may be included in the Contract Property. The Consultant hereby assigns to the Company the Consultant's entire rights in the Contract Property which it develops, improves or prepares, excluding any Consultant Property (as defined below) and waives all moral rights that it may have in respect of the Contract Property, excluding any Consultant Property (as defined below). To the extent that any concepts or other pre-existing materials or Intellectual Property Rights of the Consultant are contained in any work product, the Consultant retains ownership of such concepts or other pre-existing materials or Intellectual Property Rights of the Consultant as well as any modifications or enhancements to any of the foregoing (collectively the "Consultant Property") and grants, to the Company a non-exclusive, royalty-free licence to use such Consultant Property solely for the purposes of using the work product. "Intellectual Property Rights" means any right that is or may be granted or recognized under any Canadian or foreign legislation regarding patents, copyrights, neighbouring rights, moral rights, trade-marks, trade names, service marks, industrial designs, mask work, integrated circuit topography, privacy, publicity, celebrity and personality rights and any other statutory provision or common or civil

law principle regarding intellectual and industrial property, whether registered or unregistered, and including rights in any application for any of the foregoing.

12. **Limitation of Liability.** IN NO EVENT SHALL THE CONSULTANT OR ITS DIRECTORS, OFFICERS, EMPLOYEES, AGENTS, ADVISORS AND SHAREHOLDERS BE LIABLE FOR ANY INDIRECT, SPECIAL, INCIDENTAL, CONSEQUENTIAL, PUNITIVE OR EXEMPLARY DAMAGES, OR ANY LOSS OF REVENUE OR LOSS OF PROFITS, REGARDLESS OF THE FORM OF ACTION, WHETHER IN CONTRACT OR IN TORT, INCLUDING NEGLIGENCE, EVEN IF THE CONSULTANT HAS BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES. IN NO EVENT SHALL THE AGGREGATE LIABILITY OF THE CONSULTANT AND ITS DIRECTORS, OFFICERS, EMPLOYEES, AGENTS, ADVISORS AND SHAREHOLDERS TO THE COMPANY EXCEED THE AMOUNTS PAID BY THE COMPANY TO THE CONSULTANT REGARDLESS OF THE FORM OF ACTION, WHETHER IN CONTRACT OR IN TORT, INCLUDING NEGLIGENCE, EVEN IF THE CONSULTANT OR ITS DIRECTORS, OFFICERS, EMPLOYEES, AGENTS, ADVISORS OR SHAREHOLDERS HAVE BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES.

13. **Legal, Tax and Accounting Matters.** The Consultant will not provide any legal, tax or accounting advice either pursuant to this Agreement or otherwise. The Company will be solely responsible for engaging and instructing such legal, tax and accounting professionals as you and they deem necessary for purposes of the subject matter of this Agreement.

14. **Notices.** Any notice or other communication required or permitted to be given under this Agreement will be in writing and will be delivered to:

(a) in the case of the Company: Ontario Power Generation Inc.

700 University Avenue
Toronto, ON M5G 1Z5
Canada
Attention: Peter Cuff
Email: peter.cuff@opg.com

(b) in the case of the Consultant: Polar Star Advisory Services Inc.
[redacted]
Oakville, ON [redacted]
Attention: Cliff Inskip, President
Email: [redacted]

The parties may change their respective addresses for notices by notice given in the manner set out below. Any notice or other communication will be in writing, and unless delivered personally to the addressee or to a responsible officer of the addressee, as applicable, will be given by email and will be deemed to have been given when (i) in the case of a notice delivered personally to a responsible officer of the addressee, when so delivered, and (ii) in the case of a notice delivered or given by email, on the day on which it is acknowledged as having been received by the intended recipient.

15. **Marketing and External Communications.** The Consultant shall not make any public announcement or disclosure in connection with the Consultant's engagement as an advisor to the Company, the Project, or the Application without the prior written approval of the Company. Furthermore, if marketing materials or disclosures are approved by the Company, the Consultant shall consult with the Company prior to issuing or making, and allow the Company a reasonable opportunity to comment on the content of, any approved marketing materials or disclosures.

16. **Independence.** By entering into this Agreement, the Consultant acknowledges and agrees that it has received a copy of Rule 13A of the Board's Rules of Practice and Procedure concerning expert evidence and agrees to accept the responsibilities that are or may be imposed on them by that rule with respect to testimony before the Board. A copy of the rule and the relevant form are attached as Schedules 'B' and 'C' hereto.

17. **Miscellaneous Terms.** This Agreement constitutes the entire agreement between the parties with respect to the subject matter herein and cancels and supersedes any prior understandings and agreements between the parties with respect to the subject matter herein. Each party shall execute and deliver all such further documents and instruments and do all acts and things as the other party may reasonably require to carry out the full intent and meaning of this Agreement. No failure or delay by either party in exercising any right, power or privilege hereunder shall operate as a waiver of such right, power or privilege and all waivers must be in writing. Neither party will be liable for any delay in performing or for failing to perform obligations resulting from acts of God; inclement weather; fire; explosions; floods; strikes; work stoppages or other industrial disputes; accidents; riots or civil disturbances; acts of government or from any cause whatsoever beyond its reasonable control that could not have been reasonably foreseen or avoided. This Agreement may be executed in any number of counterparts and delivered by email or other electronic means, each copy of which when so executed, whether in original or electronic format, will be deemed to be an original and all of which, when taken together, will constitute one and the same Agreement. The Consultant is an independent contractor and not an employee or agent of the Company. This Agreement will be for the benefit of and be binding upon the parties hereto and their respective successors and assigns, provided that no party may assign this Agreement or any rights or obligations hereunder without the prior written consent of the other. This Agreement and all matters relating hereto (whether in contract, statute, tort (such as negligence), or otherwise), shall be governed by, and construed in accordance with, the laws of the Province of Ontario and the federal laws of Canada applicable therein. You and we hereby submit to the non-exclusive jurisdiction of the courts of the Province of Ontario. Where a court of competent jurisdiction declares any provision of this Agreement to be invalid or unenforceable, the remaining provisions shall continue in full force and effect and all rights accrued under the enforceable provisions shall survive such declaration. No modifications of this Agreement or waiver of any term or condition hereof will be binding upon you or us, unless approved in writing by each of us.

IN WITNESS WHEREOF, the parties, intending to be legally bound hereby, have caused this Agreement to be duly executed by their duly authorized representatives.

Ontario Power Generation Inc.

Signed: Peter Cuff

Name: Peter Cuff - Assistant General Counsel

Date: October 1, 2025

Polar Star Advisory Services Inc.

Signed: Cliff Inskip

Name: Cliff Inskip

Date: October 1, 2025

[redacted]

SCHEDULE "B"

Rule 13A of the Board's Rules of Practice and Procedure

13A. Expert Evidence

13A.01 Where a party intends to engage one or more experts to give evidence in a proceeding on issues that are relevant to the expert's area of expertise, Rule 13 applies to that evidence

13A.02 An expert shall assist the OEB impartially by giving evidence that is fair and objective.

13A.03 An expert's written evidence shall, at a minimum, include the following:

a) the expert's name, business name and address, and general area of expertise;

b) the expert's qualifications, including the expert's relevant educational and professional experience in respect of each issue in the proceeding to which the expert's evidence relates;

c) the instructions provided to the expert in relation to the proceeding and, where applicable, to each issue in the proceeding to which the expert's evidence relates;

d) the specific information upon which the expert's evidence is based, including a description of any factual assumptions made and research conducted, and a list of the documents relied on by the expert in preparing the evidence;

e) in the case of evidence that is provided in response to another expert's evidence, a summary of the points of agreement and disagreement with the other expert's evidence; and

f) an acknowledgement of the expert's duty to the OEB in **Form A** to these Rules, signed by the expert.

13A.04 In a proceeding where two or more parties have engaged experts, the OEB may require two or more of the experts to:

a) in advance of the hearing, confer with each other for the purposes of, among others, narrowing issues, identifying the points on which their views differ and are in agreement, and preparing a joint written statement to be admissible as evidence at the hearing; and

b) at the hearing, appear together as a concurrent expert panel for the purposes of, among others, answering questions from the Board and others as permitted by the Board, and providing comments on the views of another expert on the same panel.

13A.05 The activities referred to in **Rule 13A.04** shall be conducted in accordance with such directions as may be given by the OEB, including as to:

a) scope and timing;

b) the involvement of any expert engaged by the Board;

c) the costs associated with the conduct of the activities;

d) the attendance or non-attendance of counsel for the parties, or of other persons, in respect of the activities referred to in paragraph (a) of **Rule 13A.04**; and

e) any issues in relation to confidentiality.

13A.06 A party that engages an expert shall ensure that the expert is made aware of, and has agreed to accept, the responsibilities that are or may be imposed on the expert as set out in this **Rule 13A** and **Form A.**[1]

[1] Attached as Schedule 'C' herein.

FORM A

Proceeding: EB-2025-0297

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is CLIFF INSKIP (*name*). I live at OAKVILLE (*city*), in the PROVINCE (*province/state*) of ONTARIO

2. I have been engaged by or on behalf of OPG (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

(a) to provide opinion evidence that is fair, objective and non-partisan;

(b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

(c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date DECEMBER 4, 2025

Cliff Inskip
Signature

Table 1
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	3,168.1	8.9%	4.98%	157.9
4	**Total Debt**	4	17,085.8	48.0%	4.98%	850.6
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	18,459.9	51.9%	9.11%	1,681.7
5b	**Total Equity**		18,509.6	52.0%	9.10%	1,684.2
6	**Rate Base Financed by Capital Structure**	5	35,595.3	100.0%	7.12%	2,534.8
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%	7.12%	2,534.8

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 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. Capital Structure proposed in Ex. C1-1-1, Att. 1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (October 31, 2025).
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
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	240.2	0.8%	4.97%	11.9
4	**Total Debt**	4	13,602.5	48.0%	4.96%	674.2
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	14,682.2	51.8%	9.11%	1337.5
5b	**Total Equity**		14,736.1	52.0%	9.09%	1,340.2
6	**Rate Base Financed by Capital Structure**	5	28,338.6	100.0%	7.11%	2,014.4
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%	7.11%	2,014.4

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 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 Capital Structure proposed in Ex. C1-1-1, Att. 1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (October 31, 2025).

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
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	1,625.1	6.0%	4.90%	79.6
4	**Total Debt**	4	12,997.9	48.0%	4.90%	636.8
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	14,021.5	51.8%	9.11%	1,277.4
5b	**Total Equity**		14,081.1	52.0%	9.09%	1,280.3
6	**Rate Base Financed by Capital Structure**	5	27,079.0	100.0%	7.07%	1,914.1
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%	7.07%	1,914.1

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 Capital Structure proposed in Ex. C1-1-1, Att. 1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (October 31, 2025).
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
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	3,726.7	14.3%	4.78%	178.3
4	**Total Debt**	4	12,476.3	48.0%	4.78%	596.6
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	13,450.0	51.7%	9.11%	1,225.3
5b	**Total Equity**		13,516.0	52.0%	9.09%	1,228.5
6	**Rate Base Financed by Capital Structure**	5	25,992.3	99.9%	7.02%	1,825.0
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%	7.02%	1,826.1

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 Capital Structure proposed in Ex. C1-1-1, Att. 1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (October 25, 2025).
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 5
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	5,028.3	20.3%	4.58%	230.2
4	**Total Debt**	4	11,918.3	48.0%	4.60%	547.7
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	12,837.6	51.7%	9.11%	1,169.5
5b	**Total Equity**		12,911.5	52.0%	9.08%	1,172.9
6	**Rate Base Financed by Capital Structure**	5	24,829.8	99.6%	6.93%	1,720.6
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%	6.92%	1,725.3

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 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 Capital Structure proposed in Ex. C1-1-1, Att. 1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (October 31, 2025).

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 6
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital - OPG
Calendar Year Ending December 31, 2026

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	1.8%	2.47%	16.1
2	**Existing/Planned Long-Term Debt**	2	5,445.6	23.4%	4.42%	240.6
3	**Other Long-Term Debt Provision**	3	6,935.4	29.8%	4.42%	306.4
4	**Total Debt**	4	12,795.3	55.0%	4.40%	563.2
5	**Common Equity**	4	10,468.8	45.0%	5.06%	530.0
6	**Rate Base Financed by Capital Structure**	5	23,264.1	99.1%	4.70%	1,093.2
7	**Adjustment for Lesser of UNL or ARC**	5, 6	202.5	0.9%	4.72%	9.6
8	**Rate Base**		23,466.6	100.0%	4.70%	1,102.8

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 8, line 27.

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 per the OEB-approved settlement proposal in EB-2020-0290. Return on Equity as calculated in Ex. I1-1-1, Table 5.

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).

Table 7
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital - OPG
Calendar Year Ending December 31, 2025

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	209.2	1.0%	2.90%	12.0
2	**Existing/Planned Long-Term Debt**	2	6,074.9	28.7%	4.03%	244.6
3	**Other Long-Term Debt Provision**	3	5,339.3	25.3%	4.03%	215.0
4	**Total Debt**	4	11,623.5	55.0%	4.06%	471.6
5	**Common Equity**	4	9,510.1	45.0%	12.72%	1,209.3
6	**Rate Base Financed by Capital Structure**	5	21,133.7	98.5%	7.95%	1,680.9
7	**Adjustment for Lesser of UNL or ARC**	5, 6	327.8	1.5%	4.72%	15.5
8	**Rate Base**		21,461.5	100.0%	7.90%	1,696.4

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 7, line 36.
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 per the OEB-approved settlement proposal in EB-2020-0290. Return on Equity as calculated in Ex. I1-1-1 Table 4.
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).

Table 8
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital - OPG
Calendar Year Ending 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	124.5	0.6%	4.79%	9.4
2	**Existing/Planned Long-Term Debt**	2	4,306.1	22.5%	3.92%	168.9
3	**Other Long-Term Debt Provision**	3	6,106.1	31.9%	3.92%	239.5
4	**Total Debt**	4	10,536.8	55.0%	3.97%	417.8
5	**Common Equity**	4,7	8,621.0	45.0%	5.86%	505.2
6	**Rate Base Financed by Capital Structure**	5	19,157.8	97.0%	4.82%	923.0
7	**Adjustment for Lesser of UNL or ARC**	5, 6	591.4	3.0%	4.72%	27.9
8	**Rate Base**		19,749.1	100.0%	4.82%	950.9

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 6, line 34.

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 per the OEB-approved settlement proposal in EB-2020-0290. 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 Ex. C2-1-1 Table 2, line 28. Cost rate from Ex. C2-1-1, Table 1b, line 14, col (d).

7 Refer to Ex. C1-1-1, Table 8a for the reconciliation of return on equity to the 2024 audited financial statements

Table 8a
Capitalization and Cost of Capital
Reconciliation of Audited Financial Statements to Regulatory Return on Equity
Calendar Year Ending December 31, 2024

Line No.	Description	Note	Regulated Hydroelectric	Nuclear	(a)+(b) Total
			(a)	(b)	(c)
1	**Earnings (loss) before interest and income taxes (EBIT) per OPG's Audited Financial Statements (AFS)**	1	584.1	229.6	813.7
	Adjustments:				
2	**Bruce Lease Revenues Net of Costs**	2	0.0	46.9	46.9
3	**Excluded Regulated Segment Costs**	3	2.9	18.4	21.3
4	**Regulatory Accounting Timing Differences**	4	8.2	(28.9)	(20.7)
5	**Other**		2.0	1.3	3.3
6	**Accounting EBIT** (line 1+2+3+4+5+6)		**597.2**	**267.3**	**864.5**
7	**Accounting Expenses/Revenues not Included in Regulatory EBIT**	5	0.0	6.3	6.3
8	**Differences Between Accounting and Regulatory Treatment**	5	(3.6)	(8.4)	(12.0)
9	**Deemed Cost of Capital**	5	(127.8)	(240.1)	(367.8)
10	**Regulatory Earnings Before Tax** (line 7+8+9+10)		465.9	25.1	491.0
11	**Regulatory Income Tax on Regulated Assets**	5	(6.7)	20.9	14.2
12	**Regulatory Return on Equity** (line 11+12)		**459.2**	**46.0**	**505.2**

Notes:

1 Per OPG's 2024 audited financial statements, *Note 20 - Business Segments.* Col. (b), line 1 comprises both nuclear generation and nuclear waste management segments. There may be differences due to rounding.

2 Amounts represent revenues net of costs related to the Bruce Lease as recorded in the EBIT per AFS.

3 Amounts represent costs reported in the regulated segment EBIT per AFS that have been excluded from the determination of the revenue requirements and therefore do no impact regulatory return on equity.

4 Adjustment captures:
- Amounts recorded for eligible projects in the 2022-2026 IR term for the hydroelectric Capacity Refurbishment Variance Account are not recognized in EBIT per AFS until the end of the IR term; and
- Amounts recorded for eligible costs in the Pickering B Variance Account pursuant to the July 2025 amendment to O. Reg. 53/05 were accrued in EBIT per AFS prior to such amounts being recorded in the account.

5 Per OPG's 2024 annual regulatory return on equity filing, found at https://www.opg.com/reporting/regulatory-reporting/
For line 7, see: Table 2, line 2 less line 3.
For line 8, see: Table 2, line 4 less line 5 less line 6.
For line 9, see: Table 2, line 10 less line 8 less line 9.
For line 11, see: Table 2, line 12 x -1.

Table 9
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital - OPG
Calendar Year Ending 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	11.9	0.1%	5.20%	4.2
2	**Existing/Planned Long-Term Debt**	2	3,793.3	21.6%	3.77%	143.1
3	**Other Long-Term Debt Provision**	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	7,893.6	45.0%	13.71%	1,082.0
6	**Rate Base Financed by Capital Structure**	5	17,541.2	98.3%	8.26%	1,449.7
7	**Adjustment for Lesser of UNL or ARC**	5, 6	300.2	1.7%	4.79%	14.4
8	**Rate Base**		17,841.4	100.0%	8.21%	1,464.1

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

2 Ex. C1-1-2 Table 5, line 28.

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 per the OEB-approved settlement proposal in EB-2020-0290. 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 Ex. C2-1-1 Table 2, line 28. Cost rate from Ex. C2-1-1, Section 4.1.4.

7 Refer to Ex. C1-1-1, Table 9a for the reconciliation of return on equity to the 2023 audited financial statements

Table 9a
Capitalization and Cost of Capital
Reconciliation of Audited Financial Statements to Regulatory Return on Equity
Calendar Year Ending December 31, 2023

Line No.	Description	Note	Regulated Hydroelectric	Nuclear	(a)+(b) Total
			(a)	(b)	(c)
1	**Earnings (loss) before interest and income taxes (EBIT) per OPG's Audited Financial Statements (AFS)**	1	575.9	937.2	1,513.1
	Adjustments:				
2	**Bruce Lease Revenues Net of Costs**	2	0.0	39.8	39.8
3	**Excluded Regulated Segment Costs**	3	2.4	13.8	16.2
4	**Regulatory Accounting Timing Differences**	4	7.0	0.0	7.0
5	**Other**		0.4	(0.3)	0.0
6	**Accounting EBIT (includes rounding)** (line 1+2+3+4+5)		**585.7**	**990.5**	**1,576.2**
7	**Accounting Expenses/Revenues not Included in Regulatory EBIT**	5	0.0	14.5	14.5
8	**Differences Between Accounting and Regulatory Treatment**	5	(0.4)	(1.7)	(2.1)
9	**Deemed Cost of Capital**	5	(125.7)	(135.3)	(261.0)
10	**Regulatory Earnings Before Tax** (line 6+7+8+9)		459.6	867.9	1,327.6
11	**Regulatory Income Tax on Regulated Assets**	5	(104.5)	(141.1)	(245.6)
12	**Regulatory Return on Equity** (line 10+11)		**355.1**	**726.8**	**1,082.0**

Notes:

1. Per OPG's 2023 audited financial statements, Note 20 - Business Segments. Col. (b), line 1 comprises both nuclear generation and nuclear sustainability services segments. There may be differences due to rounding.
2. Amounts represent revenues net of costs related to the Bruce Lease as recorded in the EBIT per AFS.
3. Amounts represent costs reported in the regulated segment EBIT per AFS that have been excluded from the determination of the revenue requirements and therefore do no impact regulatory return on equity.
4. Adjustment captures Amounts recorded for eligible projects in the 2022-2026 IR term for the hydroelectric Capacity Refurbishment Variance Account are not recognized in EBIT per AFS until the end of the IR term.
5. Per OPG's 2023 annual regulatory return on equity filing, found at https://www.opg.com/reporting/regulatory-reporting/
   For line 7, see: Table 2, line 2 less line 3.
   For line 8, see: Table 2, line 4 less line 5 less line 6.
   For line 9, see: Table 2, line 10 less line 8 less line 9.
   For line 11, see: Table 2, line 12 x -1.

Table 10
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital - OPG
Calendar Year Ending 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	0.0	0.0%	0.79%	3.6
2	**Existing/Planned Long-Term Debt**	2	3,556.5	21.9%	3.83%	136.3
3	**Other Long-Term Debt Provision**	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	7,308.3	45.0%	12.41%	907.0
6	**Rate Base Financed by Capital Structure**	5	16,240.8	96.9%	7.71%	1,252.8
7	**Adjustment for Lesser of UNL or ARC**	5, 6	519.3	3.1%	4.83%	25.1
8	**Rate Base**		16,760.0	100.0%	7.62%	1,277.9

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
2. Ex. C1-1-2 Table 4, line 33.
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 per the OEB-approved settlement proposal in EB-2020-0290. 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 Ex. C2-1-1 Table 2, line 28. Cost rate from Ex. C2-1-1, Section 4.1.4.
7. Refer to Ex. C1-1-1, Table 10a for the reconciliation of return on equity to the 2022 audited financial statements

Table 10a
Capitalization and Cost of Capital
Reconciliation of Audited Financial Statements to Regulatory Return on Equity
Calendar Year Ending December 31, 2022

Line No.	Description	Note	Regulated Hydroelectric	Nuclear	(a)+(b) Total
			(a)	(b)	(c)
1	**Earnings (loss) before interest and income taxes (EBIT) per OPG's Audited Financial Statements (AFS)**	1	678.7	701.9	1,380.6
	Adjustments:				
2	**Bruce Lease Revenues Net of Costs**	2	0.0	44.9	44.9
3	**Excluded Regulated Segment Costs**	3	0.4	4.9	5.3
4	**Regulatory Accounting Timing Differences**	4	9.1	0.0	9.1
5	**Other**		0.5	0.5	1.0
6	**Accounting EBIT** (line 1+2+3+4+5)		**688.8**	**752.2**	**1,441.0**
7	**Accounting Expenses/Revenues not Included in Regulatory EBIT**	5	0.0	8.7	8.7
8	**Differences Between Accounting and Regulatory Treatment**	5	(0.4)	(1.7)	(2.1)
9	**Deemed Cost of Capital**	5	(136.8)	(184.3)	(321.2)
10	**Regulatory Earnings Before Tax** (line 6+7+8+9)		551.6	574.9	1,126.4
11	**Regulatory Income Tax on Regulated Assets**	5	(121.6)	(97.8)	(219.4)
12	**Regulatory Return on Equity** (line 10+11)		**430.0**	**477.1**	**907.0**

Notes:

1 Per OPG's 2022 audited financial statements, Note 20 - Business Segments. Col. (b), line 1 comprises both nuclear generation and nuclear sustainability services segments. There may be differences due to rounding.

2 Amounts represent revenues net of costs related to the Bruce Lease as recorded in the EBIT per AFS.

3 Amounts represent costs reported in the regulated segment EBIT per AFS that have been excluded from the determination of the revenue requirements and therefore do no impact regulatory return on equity.

4 Adjustment captures Amounts recorded for eligible projects in the 2022-2026 IR term for the hydroelectric Capacity Refurbishment Variance Account are not recognized in EBIT per AFS until the end of the IR term;

5 Per OPG's 2022 annual regulatory return on equity filing, found at https://www.opg.com/reporting/regulatory-reporting/
For line 7, see: Table 2, line 2 less line 3.
For line 8, see: Table 2, line 4 less line 5 less line 6.
For line 9, see: Table 2, line 10 less line 8 less line 9.
For line 11, see: Table 2, line 12 x -1

Table 11
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital - OPG
Calendar Year Ending December 31, 2021

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	7.9	0.0%	0.21%	4.6
2	**Existing/Planned Long-Term Debt**	2	3,639.1	22.7%	3.87%	140.9
3	**Other Long-Term Debt Provision**	3	5,176.2	32.3%	3.87%	200.4
4	**Total Debt**	4	8,823.2	55.0%	3.92%	345.9
5	**Common Equity**	4	7,219.0	45.0%	10.79%	778.6
6	**Rate Base Financed by Capital Structure**	5	16,042.2	97.7%	7.01%	1,124.5
7	**Adjustment for Lesser of UNL or ARC**	5, 6	376.2	2.3%	4.87%	18.3
8	**Rate Base**		16,418.4	100.0%	6.96%	1,142.8

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 34.
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 Ex. C2-1-1 Table 2, line 28. Cost rate from Ex. C2-1-1, Section 4.1.4.
7 Refer to Ex. C1-1-1, Table 11a for the reconciliation of return on equity to the 2021 audited financial statements

Table 11a
Capitalization and Cost of Capital
Reconciliation of Audited Financial Statements to Regulatory Return on Equity
Calendar Year Ending December 31, 2021

Line No.	Description	Note	Regulated Hydroelectric	Nuclear	(a)+(b) Total
			(a)	(b)	(c)
1	**Earnings (loss) before interest and income taxes (EBIT) per OPG's Audited Financial Statements (AFS)**	1	697.4	488.5	1,185.9
	Adjustments:				
2	**Bruce Lease Revenues Net of Costs**	2	0.0	32.9	32.9
3	**Excluded Regulated Segment Costs**	3	0.7	5.1	5.8
4	**Other**		1.4	(0.7)	0.6
5	**Accounting EBIT** (line 1+2+3+4)		**699.5**	**525.7**	**1,225.2**
6	**Accounting Expenses/Revenues not Included in Regulatory EBIT**	4	0.0	33.8	33.8
7	**Differences Between Accounting and Regulatory Treatment**	4	(0.5)	0.0	(0.5)
8	**Deemed Cost of Capital**	4	(158.9)	(186.3)	(345.2)
9	**Regulatory Earnings Before Tax** (line 5+6+7+8)		540.1	373.2	913.3
10	**Regulatory Income Tax on Regulated Assets**	4	(106.3)	(28.4)	(134.7)
11	**Regulatory Return on Equity** (line 9+10)		**433.8**	**344.8**	**778.6**

Notes:
1. Per OPG's 2021 audited financial statements, Note 19 - Business Segments. Col. (b), line 1 comprises both nuclear generation and nuclear sustainability services segments. There may be differences due to rounding.
2. Amounts represent revenues net of costs related to the Bruce Lease as recorded in the EBIT per AFS.
3. Amounts represent costs reported in the regulated segment EBIT per AFS that have been excluded from the determination of the revenue requirements and therefore do no impact regulatory return on equity.
4. Per OPG's 2022 annual regulatory return on equity filing, found at https://www.opg.com/reporting/regulatory-reporting/
   For line 6, see: Table 2, line 2 less line 3.
   For line 7, see: Table 2, line 4 less line 5 less line 6.
   For line 8, see: Table 2, line 10 less line 8 less line 9.
   For line 10, see: Table 2, line 12 x -1.

Table 12
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital - OPG
Calendar Year Ending December 31, 2020

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	189.2	1.4%	0.70%	4.7
2	**Existing/Planned Long-Term Debt**	2	3,868.2	27.8%	4.01%	155.3
3	**Other Long-Term Debt Provision**	3	3,592.0	25.8%	4.01%	144.2
4	**Total Debt**	4	7,649.4	55.0%	3.98%	304.2
5	**Common Equity**	4	6,258.6	45.0%	17.44%	1,091.8
6	**Rate Base Financed by Capital Structure**	5	13,908.0	97.2%	10.04%	1,396.0
7	**Adjustment for Lesser of UNL or ARC**	5, 6	406.3	2.8%	4.86%	19.7
8	**Rate Base**		14,314.3	100.0%	9.89%	1,415.7

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 2, line 40.

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 Ex. C2-1-1 Table 2, line 28. Cost rate from Ex. C2-1-1, Section 4.1.4.

7 Refer to Ex. C1-1-1, Table 12a for the reconciliation of return on equity to the 2020 audited financial statements

Table 12a
Capitalization and Cost of Capital
Reconciliation of Audited Financial Statements to Regulatory Return on Equity
Calendar Year Ending December 31, 2020

Line No.	Description	Note	Regulated Hydroelectric	Nuclear	(a)+(b) Total
			(a)	(b)	(c)
1	**Earnings (loss) before interest and income taxes (EBIT) per OPG's Audited Financial Statements (AFS)**	1	660.2	979.7	1,639.9
	Adjustments:				
2	**Bruce Lease Revenues Net of Costs**	2	0.0	3.3	3.3
3	**Excluded Regulated Segment Costs**	3	0.8	5.3	6.1
4	**Other**		0.6	0.7	1.3
5	**Accounting EBIT** (line 1+2+3+4)		**661.6**	**989.0**	**1,650.6**
6	**Accounting Expenses/Revenues not Included in Regulatory EBIT**	4	0.0	43.7	43.7
7	**Differences Between Accounting and Regulatory Treatment**	4	(0.4)	0.0	(0.4)
8	**Deemed Cost of Capital**	4	(147.4)	(191.0)	(338.4)
9	**Regulatory Earnings Before Tax** (line 5+6+7+8)		513.8	841.7	1,355.5
10	**Regulatory Income Tax on Regulated Assets**	4	(95.0)	(168.7)	(263.7)
11	**Regulatory Return on Equity** (line 9+10)		**418.8**	**673.0**	**1,091.8**

Notes:

1 Per OPG's 2020 audited financial statements, Note 21 - Business Segments. Col. (b), line 1 comprises both nuclear generation and nuclear waste management segments. There may be differences due to rounding.

2 Amounts represent revenues net of costs related to the Bruce Lease as recorded in the EBIT per AFS.

3 Amounts represent costs reported in the regulated segment EBIT per AFS that have been excluded from the determination of the revenue requirements and therefore do no impact regulatory return on equity.

4 Per OPG's 2020 annual regulatory return on equity filing, found at https://www.opg.com/reporting/regulatory-reporting/
For line 6, see: Table 2, line 2 less line 3.
For line 7, see: Table 2, line 4 less line 5 less line 6.
For line 8, see: Table 2, line 10 less line 8 less line 9.
For line 10, see: Table 2, line 12 x -1.

Table 13
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital - DNNP Facilities
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**		0.0	0.0%	0.00%	0.0
2	**Existing/Planned Long-Term Debt**		0.0	0.0%	0.00%	0.0
3	**Total Debt**	1	0.0	0.0%	0.00%	0.0
4	**Common Equity**	1	6,530.0	100.0%	9.11%	594.9
5	**Rate Base Financed by Capital Structure**	2	6,530.0	100.0%	9.11%	594.9
6	**Rate Base**		6,530.0	100.0%	9.11%	594.9

Notes:
1. Capital Structure proposed in Ex. C1-1-1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (October 31, 2025).
2. The portion of rate base to be financed by the capital structure approved by the OEB

Table 14
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital - DNNP Facilities
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**		0.0	0.0%	0.00%	0.0
2	**Existing/Planned Long-Term Debt**		0.0	0.0%	0.00%	0.0
3	**Total Debt**	1	0.0	0.0%	0.00%	0.0
4	**Common Equity**	1	1,371.1	100.0%	9.11%	124.9
5	**Rate Base Financed by Capital Structure**	2	1,371.1	100.0%	9.11%	124.9
6	**Rate Base**		1,371.1	100%	9.11%	124.9

Notes:
1 Capital Structure proposed in Ex. C1-1-1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (October 31, 2025).
2 The portion of rate base to be financed by the capital structure approved by the OEB

Table 15
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital - DNNP Facilities
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**		0.0	0.0%	0.00%	0.0
2	**Existing/Planned Long-Term Debt**		0.0	0.0%	0.00%	0.0
3	**Total Debt**	1	0.0	0.0%	0.00%	0.0
4	**Common Equity**	1	2.1	100.0%	9.11%	0.2
5	**Rate Base Financed by Capital Structure**	2	2.1	100.0%	9.11%	0.2
6	**Rate Base**		2.1	100%	9.11%	0.2

Notes:
1. Capital Structure proposed in Ex. C1-1-1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (October 31, 2025).
2. The portion of rate base to be financed by the capital structure approved by the OEB

Table 16
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital - DNNP Facilities
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**		0.0	0.0%	0.00%	0.0
2	**Existing/Planned Long-Term Debt**		0.0	0.0%	0.00%	0.0
3	**Total Debt**	1	0.0	0.0%	0.00%	0.0
4	**Common Equity**	1	0.0	100.0%	9.11%	0.0
5	**Rate Base Financed by Capital Structure**	2	0.0	0.0%	0.00%	0.0
6	**Rate Base**		0.0	100%	0.00%	0.0

Notes:
1. Capital Structure proposed in Ex. C1-1-1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (October 31, 2025).
2. The portion of rate base to be financed by the capital structure approved by the OEB

Table 17
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital - DNNP Facilities
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**		0.0	0.0%	0.00%	0.0
2	**Existing/Planned Long-Term Debt**		0.0	0.0%	0.00%	0.0
3	**Total Debt**	1	0.0	0.0%	0.00%	0.0
4	**Common Equity**	1	0.0	100.0%	9.11%	0.0
5	**Rate Base Financed by Capital Structure**	2	0.0	0.0%	0.00%	0.0
6	**Rate Base**		0.0	100%	0.00%	0.0

Notes:
1. Capital Structure proposed in Ex. C1-1-1. Return on Equity reflects the last Cost of Capital Parameter Update published by the OEB (October 31, 2025).
2. The portion of rate base to be financed by the capital structure approved by the OEB

OPG'S COST OF LONG-TERM DEBT

1.0 PURPOSE

This evidence describes the methodology used to determine the amount of long-term debt and associated cost for OPG's regulated operations for the bridge years and IR term that are reflected in the proposed capitalization of OPG's rate base. It also provides the details of OPG's existing and planned long-term borrowing and associated costs for 2020-2031.

2.0 OVERVIEW

As in prior OPG applications, the long-term debt supporting OPG's regulated operations is comprised of existing and planned long-term debt issues plus, as required, a long-term debt provision to reconcile OPG's regulated debt to its OEB-approved capital structure. The summary of capitalization for the IR term is provided in Ex. C1-1-1, Tables 1 through 12 for OPG's regulated operations.

As in EB-2020-0290, OPG's main source of new long-term debt issues continues to be its Medium-Term Notes program, under which OPG typically issues 10-year and 30-year bonds. OPG also maintains credit facilities with the Ontario Electricity Financial Corporation ("OEFC") and the Ontario Financing Authority ("OFA"), both agencies of the Province of Ontario. OPG has not issued any debt under these facilities since EB-2020-0290, for the reasons discussed below.

Over the 2025-2031 period, OPG forecasts issuing approximately $10B in long-term debt that is wholly or partially attributed to its regulated operations and which will support the planned capital investments in OPG's prescribed nuclear and hydroelectric generating assets. For clarity, this does not include the forecast long-term debt issues attributed to OPG's anticipated cash contributions to DNNP LP, beginning in 2026.

While the OEFC and OFA credit facilities remain an option for OPG to support its borrowing requirements, OPG is expecting to utilize the undrawn portion of these facilities to meet liquidity requirements established by the credit rating agencies, supporting OPG's current ratings. As a result, these facilities are expected to remain undrawn. A further discussion of these liquidity requirements can be found in Ex. C1-1-3.

Certain of OPG's Medium-Term Notes are issued as Green Bonds to finance eligible projects, as previously defined under OPG's Green Bond Framework and, beginning in 2024, under OPG's Sustainable Finance Framework. The Sustainable Finance Framework superseded the Green Bond Framework and includes a broader array of eligible projects and programs, including new nuclear projects.

OPG expects most of its borrowing needs over the IR term to be sourced through its Medium-Term Note program in the Canadian bond market. OPG is also planning to establish the ability to access US bond markets during the IR term, as part of its funding risk diversification strategy to proactively manage the likelihood that its funding requirements will exceed the issuance capacity in the Canadian bond markets. OPG intends to accomplish this by registering as a Foreign Private Issuer with the U.S. Securities and Exchange Commission ("SEC"), subject to the completion of SEC reporting and compliance requirements and final approval by OPG's Board of Directors. This process is expected to take place over several years. The cost of debt assumptions in the Application are based on bond issuances in the Canadian market.

OPG has used the same methodology to determine the regulated portion of existing and planned long-term debt as was accepted by the OEB in previous payment amounts proceedings. OPG has made modifications to the application of the previously used methodology to determine the forecast cost of planned long-term debt issues, as discussed in Section 4.2 below.

3.0 METHODOLOGY

3.1 Project-Related Long-Term Debt Issues

OPG assigns all existing and planned financing related to specific projects and other investments within regulated or unregulated operations based on the nature of such project or investment. This approach includes the Green Bond and Sustainable Bond portion of the long-term debt portfolio, which is assigned on the basis of the actual allocation of funding proceeds to underlying eligible projects and investments. All financing related to projects and other specific investments that is not associated with OPG's regulated assets is assigned to unregulated operations, which for this purpose includes DNNP LP (see Ex. A1-4-4).

3.2 Corporate Long-Term Debt Issues

The portfolio of long-term debt remaining after assignment of financing related to specific projects and other investments is allocated to regulated and unregulated operations ("company-wide long-term debt").

For the IR term, OPG has applied the allocation methodology accepted by the OEB in prior payment amounts proceedings to allocate company-wide long-term debt to the regulated operations. Under this methodology, the book value of OPG's net fixed assets (gross fixed assets less accumulated depreciation plus construction work in progress plus other debt funded assets) is used to allocate the company-wide long-term debt. The net fixed asset values are adjusted to remove asset values that have been financed pursuant to project-related arrangements, and those related to nuclear liabilities (i.e., the lesser of OPG's asset retirement cost and unfunded nuclear liabilities). The adjusted relative net fixed asset ratio in respect of OPG's regulated operations is then applied to OPG's company-wide long-term debt to determine the amount of existing/planned debt to be included in the long-term debt component of OPG's capital structure for its regulated assets.

The allocation ratios are used to allocate company-wide borrowing in Ex. C1-1-2, Table 2 (2020) through Table 13 (2031). The allocation ratios are calculated in Ex. C1-1-2, Table 1. Consistent with the approach applied in prior payment amounts proceedings, OPG has used information from its most recent audited financial statements (2024) to develop the allocation factor for 2025-2031.[1]

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[1] The inclusion of the DNNP facilities in OPG's regulated assets in 2024 has a minimal impact on the allocation factor as most of the associated construction work in progress was funded by project specific financing under the Canada Infrastructure Bank facility (see Section 4.5) and therefore is removed from the factor.

4.0 COST OF EXISTING AND PLANNED NEW LONG-TERM DEBT ISSUES

4.1 Existing Debt Issues

OPG's debt continuity schedules (Ex. C1-1-2, Tables 2 through 6) provide the actual cost of debt issued and outstanding between January 1, 2020 and December 31, 2024. The average remaining term of these long-term debt issues is approximately 17 years as of December 31, 2024.

Existing Medium-Term Notes and OEFC corporate debt will be retired or refinanced at maturity depending on OPG's liquidity at that time. OPG does not plan to redeem the debt prior to its maturity; both the OEFC credit agreement and the Trust Indenture contain early prepayment penalties that make it more expensive to redeem the debt compared to a potential benefit of refinancing.

OPG's long-term debt outstanding at December 31, 2024, as reflected in OPG's 2024 financial results, is $11,750M. Project-related debt for OPG's regulated operations includes $2,016M of Green Bond proceeds assigned to OPG's regulated hydroelectric or regulated nuclear projects, $759M of drawn proceeds from the Canada Infrastructure Bank ("CIB") credit facility for the DNNP and $25M of nuclear related insurance-linked bonds.[2] As the debt from the CIB is specifically in support of the DNNP, with the anticipated transfer of the DNNP facilities to DNNP LP expected at the end of 2025 as discussed in Ex. A1-4-4, this debt is no longer attributed to OPG's regulated operations subsequent to that date. The portion of project-related debt directly associated with unregulated operations as of December 31, 2024 is $6,354M. The remaining $2,596M of company-wide long-term debt is allocated to regulated and unregulated operations based on the methodology described in Section 3.2. The CIB credit facility is discussed further in Section 4.5.

[2] Insurance-linked bonds are denoted as "ILB" in tables accompanying this schedule.

4.2 Interest Rate on Planned New Debt Issues

The rate of interest on OPG's planned long-term debt issues is determined based on forecasted borrowing rates for the Medium-Term Notes program. The assumed borrowings have a tenor of 10 years and 30 years, consistent with the transactions OPG undertakes through its Medium-Term Notes program. In addition to better matching the longer term nature of the assets that this funding supports, issuing a blend of 10 and 30-year tenors reduces near-term refinancing risk while resulting in more competitive pricing dynamics.

Borrowing rates typically comprise three components determined at the time of issuance: i) the underlying Government of Canada ("GoC") bond rate (generally considered a "risk-free rate") for each given tenor, ii) a company-specific tenor-matched credit spread above the risk-free rate, and (iii) issuance cost, including underwriting, rating agency, legal, audit and trustee fees.[3]

As in prior OPG payment amounts proceedings, the cost of planned debt issues over the 2026-2031 period is based on a forecast of the GoC bond rates for the applicable tenor and an observed OPG credit spread.[4]

OPG has made updates to the application of the above methodology to determine the cost of planned long-term debt issues in this Application, compared to previous proceedings:

- Historically, IHS Markit's Global Insight Economics ("Global Insight") was used as a third party market source for forecast GoC bond rates. As Global Insight GoC bond rate forecast was limited to 10-year bonds, previously, a simplifying assumption was made that all planned long-term debt issues would have a tenor of 10 years. In practice, OPG's actual debt issues had been (and continue to be) a combination of 10-year and 30-year tenors. With the increased volume of planned debt issues, to improve accuracy, the forecast in this Application has been determined using an equally weighted combination of 10-year

[3] In prior applications, issuance cost was included within the credit spread information provided. In this Application, it is shown separately.
[4] There are no remaining forecasted debt issues in 2025. Ex. C1-1-2, Tables 6 and 6a reflect actual issues during the year.

and 30-year durations, which required OPG to introduce other sources of forecast GoC bond rates. In parallel, OPG observed notable divergence in forecast data between Global Insight and other economist views. These factors led OPG to adopt an alternate method for forecasting GoC bond rates.

- For this rate application, 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.[5] Bloomberg forecasts currently do not extend beyond 2028 since many economists are not publishing forecasts beyond two years given the current uncertainty in the global economy. To create a more continuous forecast over the seven-year period, for the years where the Bloomberg Bond Yield Median Forecast was not available, OPG inferred such forecast 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.
- The Bloomberg Bond Yield Median Forecast surveys economists across Canadian and international financial institutions and economic research thinktanks for these rates on a monthly basis, over a forecast period. Using this forecast therefore allows for diversity of forecast information, and a more transparent source of data without relying on a single source.
- 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. 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.

The forecast of the 10-year and 30-year GoC bond rates determined using the above methodology is shown in Charts 1 and 1A, respectively. OPG’s 10-year and 30-year credit

[5] Survey as of November 21, 2025

spread based on historical three-year average data as per above is 135 basis points and 160 basis points, respectively. OPG’s 10-year and 30-year issuance cost, based on an average of historical issuances, is 12 basis points and 10 basis points, respectively. The resulting forecast rates on OPG’s planned long-term debt issues is shown in Charts 2 and 2A.

Chart 1 - Forecast 10 Year GoC Bond Rates (%)

Year	Q1	Q2	Q3	Q4
2026	3.23	3.27	3.31	3.34
2027	3.37	3.39	3.42	3.40
2028	3.42	3.53	3.56	3.59
2029	3.61	3.63	3.66	3.68
2030	3.70	3.72	3.74	3.75
2031	3.77	3.78	3.79	3.80

Chart 1A - Forecast 30 Year GoC Bond Rates (%)

Year	Q1	Q2	Q3	Q4
2026	3.66	3.67	3.68	3.70
2027	3.71	3.75	3.75	3.76
2028	3.65	3.77	3.78	3.79
2029	3.80	3.81	3.81	3.82
2030	3.83	3.83	3.84	3.84
2031	3.85	3.85	3.86	3.86

Chart 2 - Forecast 10-Year Long-Term Debt Issuance Cost (%)

Year	Q1	Q2	Q3	Q4
2026	4.70	4.74	4.78	4.81
2027	4.84	4.86	4.89	4.87
2028	4.89	5.00	5.03	5.06
2029	5.08	5.10	5.13	5.15
2030	5.17	5.19	5.21	5.22
2031	5.24	5.25	5.26	5.27

Chart 2A - Forecast 30-Year Long Term Debt Issuance Cost (%)

Year	Q1	Q2	Q3	Q4
2026	5.36	5.37	5.38	5.40
2027	5.41	5.45	5.45	5.46
2028	5.35	5.47	5.48	5.49
2029	5.50	5.51	5.51	5.52
2030	5.53	5.53	5.54	5.54
2031	5.55	5.55	5.56	5.56

4.3 Planned Long-Term Debt Issues

The total amounts of planned long-term debt issues (total company-wide and OPG prescribed facilities' project-related) are listed in Ex. C1-1-2, Table 8a (2026), Table 9a (2027), Table 10a (2028), Table 11a (2029), Table 12a (2030), and Table 13a (2031). Maturing and planned new long-term debt issues are summarized in Chart 4 below.

Chart 4 - Long-Term Debt Retirements and Planned Issues ($M)

	2026	2027	2028	2029	2030	2031	Total
Debt Issues Maturing	$50	$522	$0	$0	$0	$0	$572
Planned New Debt Issues	$0	$2,345	$2,425	$3,135	$1,320	$0	$9,225

4.5 Canada Infrastructure Bank Facility

In 2022, OPG entered into a $970 million non-revolving term credit facility with the CIB. The facility was made available to fund part of the expenditures required to prepare for the construction of the DNNP. The debt outstanding under the CIB facility will remain with OPG following the transfer of the DNNP facilities to DNNP LP. As discussed above, as it will no longer be associated with OPG's prescribed facilities, this debt is excluded from that attributed to OPG's regulated operations. Instead, under the expected partnership arrangements, OPG expects to credit or charge DNNP LP for the net financial impact to OPG resulting from the outstanding debt under the CIB facility beginning in 2026. This forecast credit or charge is reflected in the DNNP LP's proposed revenue requirements over the IR term (Ex. F2-1-1, Table 1b, line 7) and, during the period of DNNP construction, will be considered for the purposes of measuring cost performance on DNNP Unit 1 (Ex. D2-4-8).

5.0 OTHER LONG-TERM DEBT

As discussed above, OPG finances long-term assets with long-term financing. Consistent with the methodology approved in prior OPG proceedings, the Application reflects a provision for long-term debt to reconcile the debt component of OPG's regulated capital structure with the proposed rate base that financing supports. OPG's other long-term debt provision continues to be determined based on the following approach:

- The total debt for OPG's regulated operations is determined by applying OPG's proposed capital structure to its proposed regulated rate base.
- The actual and projected project-related and corporate-wide long-term debt assigned or allocated to OPG's regulated operations is deducted.

- The actual and projected portion of short-term debt allocated to OPG's regulated operations is deducted. This calculation is described in Ex. C1-1-3.
- The result is the residual long-term debt.

Consistent with prior OPG proceedings, OPG has applied the cost rate for its existing and planned long-term debt to the other long-term debt provision for the respective years.

Table 1
Capitalization and Cost of Capital
Allocation of Existing Long-term Debt - OPG ($M)

Line No.	Asset	Note	Amount 2020	2021	2022	2023	2024
			(a)	(b)	(c)	(d)	(e)
	Company-Wide:						
1	**Net Fixed Assets**	6	27,987.1	27,281.5	27,686.7	30,051.2	32,394.5
2	**Construction Work in Progress**		2,339.3	3,567.9	4,619.2	3,946.0	4,373.3
3	**Asset Values Using Project Financing**		(10,369.2)	(10,202.7)	(11,086.0)	(11,216.4)	(13,293.1)
4	**Adjusted Net Fixed Assets**		19,957.2	20,646.7	21,219.8	22,780.8	23,474.8
5	**Adjustment for Lesser of UNL or ARC**	1,2	3,187.7	3,101.2	2,592.4	2,379.5	2,291.3
6	**Adjusted Net Fixed Funded Assets** (line 4 - line 5)		16,769.5	17,545.6	18,627.4	20,401.3	21,183.5
	Regulated Operations						
7	**Net Fixed Assets**	3	15,861.4	16,028.7	16,143.3	18,793.2	20,628.6
8	**Construction Work in Progress**		2,116.2	3,095.1	4,170.0	3,349.8	3,555.6
9	**Asset Values Using Project Financing**	4	(1,687.4)	(1,666.9)	(2,024.8)	(2,235.1)	(3,880.0)
10	**Adjusted Net Fixed Assets**		16,290.1	17,456.9	18,288.5	19,907.9	20,304.2
11	**Adjustment for Lesser of UNL or ARC**	1, 5	406.3	376.2	519.3	300.2	591.4
12	**Adjusted Net Fixed Funded Assets** (line 10 - line 11)		15,883.8	17,080.7	17,769.3	19,607.7	19,712.8
13	**Total Regulated/Company-Wide Adjusted Net Fixed Funded Assets**		94.7%	97.4%	95.4%	96.1%	93.1%
	(line 12 / line 6 if <100%)						

Notes:

1 Reflects OEB direction to adjust the allocation of existing long-term debt to regulated operations to reflect the OEB's decision with respect to the unfunded nuclear liabilities (EB-2007-0905 Decision with Reasons, p. 165).

2 Methodology is as reflected in the prior OPG payment amounts applications. Company-wide adjustment is derived as follows:

Table to Note 2

Line No.	Company-Wide Lesser of UNL and ARC	2020	2021	2022	2023	2024
		(a)	(b)	(c)	(d)	(e)
	Company-Wide UNL:					
1a	C2-1-1 Table 2, line 20	549.6	433.9	519.3	300.2	591.4
2a	C2-1-1 Table 3, line 11	11,557.5	11,988.8	11,839.5	12,308.6	12,291.4
3a	C2-1-1 Table 3, line 17	8,644.5	8,894.1	9,096.4	9,269.0	9,446.3
4a	= Company Wide UNL	3,462.6	3,528.6	3,262.4	3,339.8	3,436.5
	Company-Wide ARC:					
5a	C2-1-1 Table 2, line 27	406.3	376.2	528.1	367.2	641.4
6a	+ C2-1-1 Table 3, line 24	2,781.4	2,725.0	2,064.3	2,012.3	1,649.9
7a	= Company Wide ARC	3,187.7	3,101.2	2,592.4	2,379.5	2,291.3
8a	Lesser of Company Wide UNL and ARC	3,187.7	3,101.2	2,592.4	2,379.5	2,291.3

3 Represents closing net book value of property, plant & equipment and intangible assets of the regulated business reflected in the calculation of actual rate base.

4 Represents the closing net book value of the Niagara Tunnel Project and, beginning in 2018, regulated operations projects funded by Green Bonds.

5 From Ex. C2-1-1 Table 2, line 28.

6 Represents closing net book value of property, plant & equipment and intangible assets, and other debt funded assets of OPG's consolidated company.

Table 2
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt ($M) - OPG
Outstanding During Calendar Year Ending Dec. 31, 2020

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 to 22 and Issue 24 Matured Prior to 2020							
1	**Issue 23**	2	51.5	3/22/2010	10.0	3/22/2020	4.68%	2.4
2	**Issue 25**	3	167.2	9/22/2010	10.0	9/22/2020	4.39%	7.3
3	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
4	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
5	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
6	**Issue 29**		50.0	11/22/2016	10.0	11/22/2026	3.04%	1.5
7	**Issue 30**		50.0	11/22/2016	30.0	11/22/2046	4.03%	2.0
8	**Issue 31**		200.0	2/22/2017	30.0	2/22/2047	4.12%	8.2
9	**Issue 32**		100.0	6/22/2017	30.0	6/22/2047	3.65%	3.6
10	**Issue 33**		100.0	8/22/2017	30.0	8/22/2047	3.86%	3.9
11	**Issue 34**		400.0	9/22/2017	30.0	9/22/2047	4.07%	16.3
12	**Issue 35**		496.5	10/2/2017	10.0	10/4/2027	3.43%	17.0
13	**Issue 36**		200.0	1/22/2018	30.0	1/22/2048	3.87%	7.7
14	**Issue 37**		400.0	3/22/2018	30.0	3/22/2048	4.00%	16.0
15	**Issue 38**		100.0	8/22/2019	20.0	8/22/2039	3.49%	3.5
16	**Issue 39**	1	318.0	3/16/2020	4.0	3/16/2024	1.75%	5.6
17	**Total**		3,133.2				3.80%	119.0
	Regulated Portion of Company-Wide Borrowing							
18	**Allocation**	8	2,967.7				3.80%	112.7
	Project Financing - Regulated Projects							
	Niagara 1 to 10 Matured Prior to 2020							
19	**Niagara 11**	4	3.0	1/22/2010	10.0	1/22/2020	5.44%	0.2
20	**Niagara 12**	5	20.1	4/22/2010	10.0	4/22/2020	5.73%	1.2
21	**Niagara 13**	6	19.5	7/22/2010	10.0	7/22/2020	5.57%	1.1
22	**Niagara 14**	7	40.4	10/22/2010	10.0	10/22/2020	4.87%	2.0
23	**Niagara 15**		40.0	1/24/2011	10.0	1/22/2021	5.18%	2.1
24	**Niagara 16**		35.0	4/26/2011	10.0	4/22/2021	5.34%	1.9
25	**Niagara 17**		50.0	7/22/2011	10.0	7/22/2021	5.24%	2.6
26	**Niagara 18**		60.0	10/24/2011	10.0	10/22/2021	5.74%	3.4
27	**Niagara 19**		40.0	1/22/2012	10.0	1/22/2022	5.50%	2.2
28	**Niagara 20**		35.0	4/22/2012	10.0	4/22/2022	5.36%	1.9
29	**Niagara 21**		45.0	7/22/2012	10.0	7/22/2022	5.51%	2.5
30	**Niagara 22**		30.0	10/22/2012	10.0	10/22/2022	5.52%	1.7
31	**Niagara 23**		20.0	1/22/2013	10.0	1/22/2023	5.35%	1.1
32	**Niagara 24**		20.0	4/22/2013	10.0	4/22/2023	5.37%	1.1
33	**ILB 1**		15.0	12/29/2016	5.0	1/4/2022	5.84%	0.9
34	**ILB 2**		4.3	12/29/2017	4.0	1/4/2022	5.84%	0.3
35	**ILB 3**		2.2	12/31/2018	3.0	1/4/2022	5.84%	0.1
36	**ILB 4**		3.5	12/31/2019	2.0	1/4/2022	5.84%	0.2
37	**Green Bond 1**		417.1	6/22/2018	30.0	6/22/2048	3.92%	16.3
38	**Green Bond 2**		0.4	1/18/2019	30.0	1/18/2049	4.34%	0.0
39	**Total**		900.6				4.73%	42.6
	Total Regulated Funded Long-Term Debt							
40	**Line 18+39**		3,868.2				4.01%	155.3

See Ex. C1-1-2 Table 2a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 2a
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2020
Notes to Ex. C1-1-2, Table 2

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Issue 39	3/16/2020	400.0	291.0	318.0
	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 2	Issue 23	3/22/2020	230.0	82.0	51.5
Note 3	Issue 25	9/22/2020	230.0	266.0	167.2
Note 4	Niagara 11	1/22/2020	50.0	22.0	3.0
Note 5	Niagara 12	4/22/2020	65.0	113.0	20.1
Note 6	Niagara 13	7/22/2020	35.0	204.0	19.5
Note 7	Niagara 14	10/22/2020	50.0	296.0	40.4

Note 8 Allocation ratio as per Ex. C1-1-2 Table 1, line 13, col (a).

Table 3
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2021

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 to 25 Mature Prior to 2021							
1	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
2	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
3	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
4	**Issue 29**		50.0	11/22/2016	10.0	11/22/2026	3.04%	1.5
5	**Issue 30**		50.0	11/22/2016	30.0	11/22/2046	4.03%	2.0
6	**Issue 31**		200.0	2/22/2017	30.0	2/22/2047	4.12%	8.2
7	**Issue 32**		100.0	6/22/2017	30.0	6/22/2047	3.65%	3.6
8	**Issue 33**		100.0	8/22/2017	30.0	8/22/2047	3.86%	3.9
9	**Issue 34**		400.0	9/22/2017	30.0	9/22/2047	4.07%	16.3
10	**Issue 35**		496.5	10/2/2017	10.0	10/4/2027	3.43%	17.0
11	**Issue 36**		200.0	1/22/2018	30.0	1/22/2048	3.87%	7.7
12	**Issue 37**		400.0	3/22/2018	30.0	3/22/2048	4.00%	16.0
13	**Issue 38**		100.0	8/22/2019	20.0	8/22/2039	3.49%	3.5
14	**Issue 39**		400.0	3/16/2020	4.0	3/16/2024	1.75%	7.0
15	**Total**		2,996.5				3.70%	110.7
	Regulated Portion of Company-Wide Borrowing							
16	**Allocation**	5	2,917.1				3.70%	107.8
	Project Financing - Regulated Projects							
	Niagara 1 to 14 Mature Prior to 2021							
17	**Niagara 15**	1	2.4	1/24/2011	10.0	1/22/2021	5.18%	0.1
18	**Niagara 16**	2	10.7	4/26/2011	10.0	4/22/2021	5.34%	0.6
19	**Niagara 17**	3	27.8	7/22/2011	10.0	7/22/2021	5.24%	1.5
20	**Niagara 18**	4	48.5	10/24/2011	10.0	10/22/2021	5.74%	2.8
21	**Niagara 19**		40.0	1/22/2012	10.0	1/22/2022	5.50%	2.2
22	**Niagara 20**		35.0	4/22/2012	10.0	4/22/2022	5.36%	1.9
23	**Niagara 21**		45.0	7/22/2012	10.0	7/22/2022	5.51%	2.5
24	**Niagara 22**		30.0	10/22/2012	10.0	10/22/2022	5.52%	1.7
25	**Niagara 23**		20.0	1/22/2013	10.0	1/22/2023	5.35%	1.1
26	**Niagara 24**		20.0	4/22/2013	10.0	4/22/2023	5.37%	1.1
27	**ILB 1**		15.0	12/29/2016	5.0	1/4/2022	5.84%	0.9
28	**ILB 2**		4.3	12/29/2017	4.0	1/4/2022	5.84%	0.3
29	**ILB 3**		2.2	12/31/2018	3.0	1/4/2022	5.84%	0.1
30	**ILB 4**		3.5	12/31/2019	2.0	1/4/2022	5.84%	0.2
31	**Green Bond 1**		417.1	6/22/2018	30.0	6/22/2048	3.92%	16.3
32	**Green Bond 2**		0.4	1/18/2019	30.0	1/18/2049	4.34%	0.0
33	**Total**		722.0				4.59%	33.1
	Total Regulated Funded Long-Term Debt							
34	Line 16+33		3,639.1				3.87%	140.9

See Ex. C1-1-2 Table 3a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 3a
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt ($M) - OPG
Outstanding During Calendar Year Ending Dec. 31, 2021
Notes to Ex. C1-1-2, Table 3

	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Niagara 15	1/22/2021	40.0	22.0	2.4
Note 2	Niagara 16	4/22/2021	35.0	112.0	10.7
Note 3	Niagara 17	7/22/2021	50.0	203.0	27.8
Note 4	Niagara 18	10/22/2021	60.0	295.0	48.5

Note 5 Allocation ratio as per Ex. C1-1-2 Table 1, line 13, col (b).

Numbers may not add due to rounding.

Table 4
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2022

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 to 25 Mature Prior to 2022							
1	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
2	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
3	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
4	**Issue 29**		50.0	11/22/2016	10.0	11/22/2026	3.04%	1.5
5	**Issue 30**		50.0	11/22/2016	30.0	11/22/2046	4.03%	2.0
6	**Issue 31**		200.0	2/22/2017	30.0	2/22/2047	4.12%	8.2
7	**Issue 32**		100.0	6/22/2017	30.0	6/22/2047	3.65%	3.6
8	**Issue 33**		100.0	8/22/2017	30.0	8/22/2047	3.86%	3.9
9	**Issue 34**		400.0	9/22/2017	30.0	9/22/2047	4.07%	16.3
10	**Issue 35**		496.5	10/2/2017	10.0	10/4/2027	3.43%	17.0
11	**Issue 36**		200.0	1/22/2018	30.0	1/22/2048	3.87%	7.7
12	**Issue 37**		400.0	3/22/2018	30.0	3/22/2048	4.00%	16.0
13	**Issue 38**		100.0	8/22/2019	20.0	8/22/2039	3.49%	3.5
14	**Issue 39**		400.0	3/16/2020	4.0	3/16/2024	1.75%	7.0
15	**Total**		2,996.5				3.70%	110.7
	Regulated Portion of Company-Wide Borrowing							
16	**Allocation**	12	2,858.4				3.70%	105.6
	Project Financing - Regulated Projects							
	Niagara 1 to 18 Mature Prior to 2022							
17	**Niagara 19**	4	2.4	1/22/2012	10.0	1/22/2022	5.50%	0.1
18	**Niagara 20**	5	10.7	4/22/2012	10.0	4/22/2022	5.36%	0.6
19	**Niagara 21**	6	25.0	7/22/2012	10.0	7/22/2022	5.51%	1.4
20	**Niagara 22**	7	24.2	10/22/2012	10.0	10/22/2022	5.52%	1.3
21	**Niagara 23**		20.0	1/22/2013	10.0	1/22/2023	5.35%	1.1
22	**Niagara 24**		20.0	4/22/2013	10.0	4/22/2023	5.37%	1.1
23	**ILB 1**	8	0.2	12/29/2016	5.0	1/4/2022	5.84%	0.0
24	**ILB 2**	9	0.0	12/29/2017	4.0	1/4/2022	5.84%	0.0
25	**ILB 3**	10	0.0	12/31/2018	3.0	1/4/2022	5.84%	0.0
26	**ILB 4**	11	0.0	12/31/2019	2.0	1/4/2022	5.84%	0.0
27	**ILB 5**	1	24.7	1/5/2022	5.0	1/5/2027	[redacted]	[redacted]
28	**Green Bond 1**		417.1	6/22/2018	30.0	6/22/2048	3.92%	16.3
29	**Green Bond 2**		0.4	1/18/2019	30.0	1/18/2049	4.34%	0.0
30	**Green Bond 3**	2	136.3	7/18/2022	10.0	7/19/2032	5.08%	6.9
31	**CIB 1**	3	16.9	10/14/2022	[redacted]	[redacted]	[redacted]	[redacted]
32	**Total**		698.1				4.39%	30.63
	Total Regulated Funded Long-Term Debt							
33	Line 16+32		3,556.5				3.83%	136.3

See Ex. C1-1-2 Table 4a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 4a
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2022
Notes to Ex. C1-1-2, Table 4

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	ILB 5	1/5/2022	25.0	361.0	24.7
Note 2	Green Bond 3	7/18/2022	297.9	167.0	136.3
Note 3	CIB 1	10/14/2022	78.0	79.0	16.9
	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 4	Niagara 19	1/22/2022	40.0	22.0	2.4
Note 5	Niagara 20	4/22/2022	35.0	112.0	10.7
Note 6	Niagara 21	7/22/2022	45.0	203.0	25.0
Note 7	Niagara 22	10/22/2022	30.0	295.0	24.2
Note 8	ILB 1	1/4/2022	15.0	4.0	0.2
Note 9	ILB 2	1/4/2022	4.3	4.0	0.0
Note 10	ILB 3	1/4/2022	2.2	4.0	0.0
Note 11	ILB 4	1/4/2022	3.5	4.0	0.0

Note 12 Allocation ratio as per Ex. C1-1-2 Table 1, line 13, col (c).

Numbers may not add due to rounding.

Table 5
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2023

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 to 25 Mature Prior to 2023							
1	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
2	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
3	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
4	**Issue 29**		50.0	11/22/2016	10.0	11/22/2026	3.04%	1.5
5	**Issue 30**		50.0	11/22/2016	30.0	11/22/2046	4.03%	2.0
6	**Issue 31**		200.0	2/22/2017	30.0	2/22/2047	4.12%	8.2
7	**Issue 32**		100.0	6/22/2017	30.0	6/22/2047	3.65%	3.6
8	**Issue 33**		100.0	8/22/2017	30.0	8/22/2047	3.86%	3.9
9	**Issue 34**		400.0	9/22/2017	30.0	9/22/2047	4.07%	16.3
10	**Issue 35**		496.5	10/2/2017	10.0	10/4/2027	3.43%	17.0
11	**Issue 36**		200.0	1/22/2018	30.0	1/22/2048	3.87%	7.7
12	**Issue 37**		400.0	3/22/2018	30.0	3/22/2048	4.00%	16.0
13	**Issue 38**		100.0	8/22/2019	20.0	8/22/2039	3.49%	3.5
14	**Issue 39**		400.0	3/16/2020	4.0	3/16/2024	1.75%	7.0
15	**Total**		2,996.5				3.70%	110.7
	Regulated Portion of Company-Wide Borrowing							
16	**Allocation**	6	2,879.9				3.70%	106.4
	Project Financing - Regulated Projects							
	Niagara 1 to 22 and ILB 1 to 4 Mature Prior to 2023							
17	**Niagara 23**	4	1.2	1/22/2013	10.0	1/22/2023	5.35%	0.1
18	**Niagara 24**	5	6.1	4/22/2013	10.0	4/22/2023	5.37%	0.3
19	**Green Bond 1**		417.1	6/22/2018	30.0	6/22/2048	3.92%	16.3
20	**Green Bond 2**		0.4	1/18/2019	30.0	1/18/2049	4.34%	0.0
21	**Green Bond 3**		297.9	7/18/2022	10.0	7/19/2032	5.08%	15.1
22	**ILB 5**		25.0	1/5/2022	5.0	1/5/2027	[redacted]	
23	**CIB 1**		78.0	10/14/2022	[redacted]			
24	**CIB 2**	1	61.7	4/11/2023				
25	**CIB 3**	2	23.4	9/29/2023				
26	**CIB 4**	3	2.6	12/18/2023				
27	**Total**		913.5				4.02%	36.7
	Total Regulated Funded Long-Term Debt							
28	Line 16+27		3,793.3				3.77%	143.1

See Ex. C1-1-2 Table 5a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 5a
Capitalization and Cost of Capital
Summary of Existing Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2023
Notes to Ex. C1-1-2, Table 5

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	CIB 2	4/11/2023	85.0	265.0	61.7
Note 2	CIB 3	9/29/2023	91.0	94.0	23.4
Note 3	CIB 4	12/18/2023	68.0	14.0	2.6
	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 4	Niagara 23	1/22/2023	20.0	22.0	1.2
Note 5	Niagara 24	4/22/2023	20.0	112.0	6.1

Note 6 Allocation ratio as per Ex. C1-1-2 Table 1, line 13, col (d).

Numbers may not add due to rounding.

Table 6
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2024

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 to 25 Mature Prior to 2024							
1	**Issue 26**		150.0	3/22/2011	29.9	3/22/2041	5.40%	8.1
2	**Issue 27**		150.0	9/22/2011	29.9	9/22/2041	4.74%	7.1
3	**Issue 28**		200.0	3/22/2012	29.9	3/22/2042	4.36%	8.7
4	**Issue 29**		50.0	11/22/2016	10.0	11/22/2026	3.04%	1.5
5	**Issue 30**		50.0	11/22/2016	29.9	11/22/2046	4.03%	2.0
6	**Issue 31**		200.0	2/22/2017	29.9	2/22/2047	4.12%	8.2
7	**Issue 32**		100.0	6/22/2017	29.9	6/22/2047	3.65%	3.6
8	**Issue 33**		100.0	8/22/2017	29.9	8/22/2047	3.86%	3.9
9	**Issue 34**		400.0	9/22/2017	29.9	9/22/2047	4.07%	16.3
10	**Issue 35**		496.5	10/2/2017	10.0	10/4/2027	3.43%	17.0
11	**Issue 36**		200.0	1/22/2018	29.9	1/22/2048	3.87%	7.7
12	**Issue 37**		400.0	3/22/2018	29.9	3/22/2048	4.00%	16.0
13	**Issue 38**		100.0	8/22/2019	20.0	8/22/2039	3.49%	3.5
14	**Issue 39**	9	83.1	3/16/2020	4.0	3/16/2024	1.75%	1.5
15	**Total**		2,679.5				3.92%	105.2
	Regulated Portion of Company-Wide Borrowing							
16	**Allocation**	10	2,493.5				3.92%	97.9
	Project Financing - Regulated Projects							
	Niagara 1 to 24 and ILB 1 to 4 Mature Prior to 2024							
17	**Green Bond 1**		417.1	6/22/2018	29.9	6/22/2048	3.92%	16.3
18	**Green Bond 2**		0.4	1/18/2019	29.9	1/18/2049	4.34%	0.0
19	**Green Bond 3**		297.9	7/18/2022	10.0	7/19/2032	5.08%	15.1
20	**ILB 5**		25.0	1/5/2022	5.0	1/5/2027	[redacted]	[redacted]
21	**CIB 1**		78.0	10/14/2022	[redacted]	[redacted]	[redacted]	[redacted]
22	**CIB 2**		85.0	4/11/2023	[redacted]	[redacted]	[redacted]	[redacted]
23	**CIB 3**		91.0	9/29/2023	[redacted]	[redacted]	[redacted]	[redacted]
24	**CIB 4**		68.0	12/18/2023	[redacted]	[redacted]	[redacted]	[redacted]
25	**CIB 5**	5	60.0	3/22/2024	[redacted]	[redacted]	[redacted]	[redacted]
26	**CIB 6**	6	46.6	6/19/2024	[redacted]	[redacted]	[redacted]	[redacted]
27	**CIB 7**	7	38.3	9/25/2024	[redacted]	[redacted]	[redacted]	[redacted]
28	**CIB 8**	8	5.0	12/18/2024	[redacted]	[redacted]	[redacted]	[redacted]
29	**Green Bond 4**	1	253.8	6/28/2024	10.0	6/28/2034	4.98%	12.6
30	**Green Bond 5**	2	250.9	6/28/2024	29.9	6/28/2054	5.17%	13.0
31	**Green Bond 6**	3	64.0	9/11/2024	9.8	6/28/2034	4.43%	2.8
32	**Green Bond 7**	4	31.9	9/11/2024	29.7	6/28/2054	4.85%	1.5
33	**Total**		1,812.6				3.92%	71.0
	Total Regulated Funded Long-Term Debt							
34	Line 16+33		4,306.1				3.92%	168.9

See Ex. C1-1-2 Table 6a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 6a
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2024
Notes to Ex. C1-1-2, Table 6

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Green Bond 4	6/28/2024	496.7	187.0	253.8
Note 2	Green Bond 5	6/28/2024	491.0	187.0	250.9
Note 3	Green Bond 6	9/11/2024	209.0	112.0	64.0
Note 4	Green Bond 7	9/11/2024	104.1	112.0	31.9
Note 5	CIB 5	3/22/2024	77.0	285.0	60.0
Note 6	CIB 6	6/19/2024	87.0	196.0	46.6
Note 7	CIB 7	9/25/2024	143.0	98.0	38.3
Note 8	CIB 8	12/18/2024	130.0	14.0	5.0
	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 9	Issue 39	3/16/2024	400.0	76.0	83.1

Note 10 Allocation ratio as per Ex. C1-1-2 Table 1, line 13, col (e).

Table 7
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2025

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 to 25, 39 Mature Prior to 2025							
1	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
2	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
3	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
4	**Issue 29**		50.0	11/22/2016	10.0	11/22/2026	3.04%	1.5
5	**Issue 30**		50.0	11/22/2016	30.0	11/22/2046	4.03%	2.0
6	**Issue 31**		200.0	2/22/2017	30.0	2/22/2047	4.12%	8.2
7	**Issue 32**		100.0	6/22/2017	30.0	6/22/2047	3.65%	3.6
8	**Issue 33**		100.0	8/22/2017	30.0	8/22/2047	3.86%	3.9
9	**Issue 34**		400.0	9/22/2017	30.0	9/22/2047	4.07%	16.3
10	**Issue 35**		496.5	10/2/2017	10.0	10/4/2027	3.43%	17.0
11	**Issue 36**		200.0	1/22/2018	30.0	1/22/2048	3.87%	7.7
12	**Issue 37**		400.0	3/22/2018	30.0	3/22/2048	4.00%	16.0
13	**Issue 38**		100.0	8/22/2019	20.0	8/22/2039	3.49%	3.5
14	**Total**		**2,596.5**				**3.99%**	**103.7**
	Regulated Portion of Company-Wide Borrowing							
15	**Allocation**	6	2,416.2				3.99%	96.5
	Project Financing - Regulated Projects							
	Niagara 1 to 24 and ILB 1 to 4 Mature Prior to 2025							
16	**Green Bond 1**		417.1	6/22/2018	30.0	6/22/2048	3.92%	16.3
17	**Green Bond 2**		0.4	1/18/2019	30.0	1/18/2049	4.34%	0.0
18	**Green Bond 3**		297.9	7/18/2022	10.0	7/19/2032	5.08%	15.1
19	**ILB 5**		25.0	1/5/2022	5.0	1/5/2027	[redacted]	
20	**CIB 1**		78.0	10/14/2022	[redacted]			
21	**CIB 2**		85.0	4/11/2023	[redacted]			
22	**CIB 3**		91.0	9/29/2023	[redacted]			
23	**CIB 4**		68.0	12/18/2023	[redacted]			
24	**CIB 5**	4	52.3	3/22/2024	[redacted]			
25	**CIB 6**		87.0	6/19/2024	[redacted]			
26	**CIB 7**	5	97.2	9/25/2024	[redacted]			
27	**CIB 8**		130.0	12/18/2024	[redacted]			
28	**CIB 9**	3	129.1	4/2/2025	[redacted]			
29	**Green Bond 4**		496.7	6/28/2024	10.0	6/28/2034	4.98%	24.7
30	**Green Bond 5**		491.0	6/28/2024	30.0	6/28/2054	5.17%	25.4
31	**Green Bond 6**		209.0	9/11/2024	9.8	6/28/2034	4.43%	9.3
32	**Green Bond 7**		104.1	9/11/2024	29.8	6/28/2054	4.85%	5.1
33	**Green Bond 8**	1	400.2	3/13/2025	10.0	3/13/2035	4.45%	17.8
34	**Green Bond 9**	2	399.8	3/13/2025	30.0	3/13/2055	4.97%	19.9
35	**Total**		**3,658.7**				**4.05%**	**148.1**
	Total Regulated Funded Long-Term Debt							
36	Line 14+35		6,074.9				4.03%	244.6

See Ex. C1-1-2 Table 7a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 7a
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2025
Notes to Ex. C1-1-2, Table 7

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Green Bond 8	3/13/2025	496.8	294	400.2
Note 2	Green Bond 9	3/13/2025	496.3	294	399.8
Note 3	CIB 9	4/2/2025	172.0	274	129.1
	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 4	CIB 5	9/5/2025	77.0	248	52.3
Note 5	CIB 7	9/5/2025	143.0	248	97.2

Note 6 Allocation ratio as per Ex. C1-1-2 Table 1, line 13, col (e).

Table 8
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2026

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 to 25, 39 Mature Prior to 2026							
1	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
2	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
3	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
4	**Issue 29**	1	44.7	11/22/2016	10.0	11/22/2026	3.04%	1.4
5	**Issue 30**		50.0	11/22/2016	30.0	11/22/2046	4.03%	2.0
6	**Issue 31**		200.0	2/22/2017	30.0	2/22/2047	4.12%	8.2
7	**Issue 32**		100.0	6/22/2017	30.0	6/22/2047	3.65%	3.6
8	**Issue 33**		100.0	8/22/2017	30.0	8/22/2047	3.86%	3.9
9	**Issue 34**		400.0	9/22/2017	30.0	9/22/2047	4.07%	16.3
10	**Issue 35**		496.5	10/2/2017	10.0	10/4/2027	3.43%	17.0
11	**Issue 36**		200.0	1/22/2018	30.0	1/22/2048	3.87%	7.7
12	**Issue 37**		400.0	3/22/2018	30.0	3/22/2048	4.00%	16.0
13	**Issue 38**		100.0	8/22/2019	20.0	8/22/2039	3.49%	3.5
14	**Total**		**2,591.1**				**4.00%**	**103.5**
	Regulated Portion of Company-Wide Borrowing							
15	**Allocation**	2	2,411.2				4.00%	96.4
	Project Financing - Regulated Projects							
	Niagara 1 to 24 and ILB 1 to 4 Mature Prior to 2026							
16	**Green Bond 1**		417.1	6/22/2018	30.0	6/22/2048	3.92%	16.3
17	**Green Bond 2**		0.4	1/18/2019	30.0	1/18/2049	4.34%	0.0
18	**Green Bond 3**		297.9	7/18/2022	10.0	7/19/2032	5.08%	15.1
19	**ILB 5**		25.0	1/5/2022	5.0	1/5/2027	6.34%	1.6
20	**Green Bond 4**		496.7	6/28/2024	10.0	6/28/2034	4.98%	24.7
21	**Green Bond 5**		491.0	6/28/2024	30.0	6/28/2054	5.17%	25.4
22	**Green Bond 6**		209.0	9/11/2024	9.8	6/28/2034	4.43%	9.3
23	**Green Bond 7**		104.1	9/11/2024	29.8	6/28/2054	4.85%	5.1
24	**Green Bond 8**		496.8	3/13/2025	10.0	3/13/2035	4.45%	22.1
25	**Green Bond 9**		496.3	3/13/2025	30.0	3/13/2055	4.97%	24.7
26	**Total**		**3,034.3**				**4.75%**	**144.3**
	Total Regulated Funded Long-Term Debt							
27	Line 15 - 26		**5,445.6**				**4.42%**	**240.6**

See Ex. C1-1-2 Table 8a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 8a
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2026
Notes to Ex. C1-1-2, Table 8

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Issue 29	11/22/2026	50.0	326.0	44.7

Note 2 Allocation ratio as per Ex. C1-1-2 Table 1, line 13, col (e).

Table 9
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2027

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 to 25, 29, 39 Mature Prior to 2027							
1	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
2	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
3	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
4	**Issue 30**		50.0	11/22/2016	30.0	11/22/2046	4.03%	2.0
5	**Issue 31**		200.0	2/22/2017	30.0	2/22/2047	4.12%	8.2
6	**Issue 32**		100.0	6/22/2017	30.0	6/22/2047	3.65%	3.6
7	**Issue 33**		100.0	8/22/2017	30.0	8/22/2047	3.86%	3.9
8	**Issue 34**		400.0	9/22/2017	30.0	9/22/2047	4.07%	16.3
9	**Issue 35**	6	376.8	10/2/2017	10.0	10/4/2027	3.43%	12.9
10	**Issue 36**		200.0	1/22/2018	30.0	1/22/2048	3.87%	7.7
11	**Issue 37**		400.0	3/22/2018	30.0	3/22/2048	4.00%	16.0
12	**Issue 38**		100.0	8/22/2019	20.0	8/22/2039	3.49%	3.5
13	**Issue 40**	1, 9	464.0	3/15/2027	10.0	3/15/2037	4.84%	22.5
14	**Issue 41**	2, 9	464.0	3/15/2027	30.0	3/15/2057	5.41%	25.1
15	**Issue 42**	3, 9	171.6	9/15/2027	10.0	9/15/2037	4.89%	8.4
16	**Issue 43**	4, 9	171.6	9/15/2027	30.0	9/15/2057	5.45%	9.4
17	**Total**		**3,698.0**				**4.42%**	**163.4**
	Regulated Portion of Company-Wide Borrowing							
18	**Allocation**	8	3,441.3				4.42%	152.0
	Project Financing - Regulated Projects							
	Niagara 1 to 24 and ILB 1 to 4 Mature Prior to 2027							
19	**Green Bond 1**		417.1	6/22/2018	30.0	6/22/2048	3.92%	16.3
20	**Green Bond 2**		0.4	1/18/2019	30.0	1/18/2049	4.34%	0.0
21	**Green Bond 3**		297.9	7/18/2022	10.0	7/19/2032	5.08%	15.1
22	**ILB 5**	7	0.3	1/5/2022	5.0	1/5/2027	6.34%	0.0
23	**ILB 6**	5	24.7	1/5/2027	5.0	1/5/2032	7.08%	1.8
24	**Green Bond 4**		496.7	6/28/2024	10.0	6/28/2034	4.98%	24.7
25	**Green Bond 5**		491.0	6/28/2024	30.0	6/28/2054	5.17%	25.4
26	**Green Bond 6**		209.0	9/11/2024	9.8	6/28/2034	4.43%	9.3
27	**Green Bond 7**		104.1	9/11/2024	29.8	6/28/2054	4.85%	5.1
28	**Green Bond 8**		496.8	3/13/2025	10.0	3/13/2035	4.45%	22.1
29	**Green Bond 9**		496.3	3/13/2025	30.0	3/13/2055	4.97%	24.7
30	**Total**		**3,034.4**				**4.76%**	**144.4**
	Total Regulated Funded Long-Term Debt							
31	Line 18+30		**6,475.7**				**4.58%**	**296.5**

See Ex. C1-1-2 Table 9a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 9a
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2027
Notes to Ex. C1-1-2, Table 9

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Issue 40	3/15/2027	580.0	292.0	464.0
Note 2	Issue 41	3/15/2027	580.0	292.0	464.0
Note 3	Issue 42	9/15/2027	580.0	108.0	171.6
Note 4	Issue 43	9/15/2027	580.0	108.0	171.6
Note 5	ILB 6	1/5/2027	25.0	361.0	24.7
	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 6	Issue 35	10/4/2027	496.5	277.0	376.8
Note 7	ILB 5	1/5/2027	25.0	5.0	0.3

Note 8 Allocation ratio as per Ex. C1-1-2 Table 1, line 13, col (e).

Note 9 Future issue rate reference Bloomberg (Nov 21, 2025).

Issue 40

GOC & OPG Spread	
GOC Q1-27	3.37%
OPG Spread	1.35%
Issuance Cost	0.12%
Effective Rate	4.84%

Issue 41

GOC & OPG Spread	
GOC Q1-27	3.71%
OPG Spread	1.60%
Issuance Cost	0.10%
Effective Rate	5.41%

Issue 42

GOC & OPG Spread	
GOC Q3-27	3.42%
OPG Spread	1.35%
Issuance Cost	0.12%
Effective Rate	4.89%

Issue 43

GOC & OPG Spread	
GOC Q3-27	3.75%
OPG Spread	1.60%
Issuance Cost	0.10%
Effective Rate	5.45%

Numbers may not add due to rounding.

Table 10
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2028

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 to 25, 29, 35, 39 Mature Prior to 2028							
1	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
2	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
3	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
4	**Issue 30**		50.0	11/22/2016	30.0	11/22/2046	4.03%	2.0
5	**Issue 31**		200.0	2/22/2017	30.0	2/22/2047	4.12%	8.2
6	**Issue 32**		100.0	6/22/2017	30.0	6/22/2047	3.65%	3.6
7	**Issue 33**		100.0	8/22/2017	30.0	8/22/2047	3.86%	3.9
8	**Issue 34**		400.0	9/22/2017	30.0	9/22/2047	4.07%	16.3
9	**Issue 36**		200.0	1/22/2018	30.0	1/22/2048	3.87%	7.7
10	**Issue 37**		400.0	3/22/2018	30.0	3/22/2048	4.00%	16.0
11	**Issue 38**		100.0	8/22/2019	20.0	8/22/2039	3.49%	3.5
12	**Issue 40**		580.0	3/15/2027	10.0	3/15/2037	4.84%	28.1
13	**Issue 41**		580.0	3/15/2027	30.0	3/15/2057	5.41%	31.4
14	**Issue 42**		580.0	9/15/2027	10.0	9/15/2037	4.89%	28.4
15	**Issue 43**		580.0	9/15/2027	30.0	9/15/2057	5.45%	31.6
16	**Issue 44**	1, 8	323.1	3/15/2028	10.0	3/15/2038	4.89%	15.8
17	**Issue 45**	2, 8	323.1	3/15/2028	30.0	3/15/2058	5.35%	17.3
18	**Issue 46**	3, 8	221.3	6/15/2028	10.0	6/15/2038	5.00%	11.1
19	**Issue 47**	4, 8	221.3	6/15/2028	30.0	6/15/2058	5.47%	12.1
20	**Issue 48**	5, 8	119.5	9/15/2028	10.0	9/15/2038	5.03%	6.0
21	**Issue 49**	6, 8	118.0	9/15/2028	30.0	9/15/2058	5.48%	6.5
22	**Total**		**5,696.4**				**4.80%**	**273.3**
	Regulated Portion of Company-Wide Borrowing							
23	**Allocation**	7	5,300.9				4.80%	254.4
	Project Financing - Regulated Projects							
	Niagara 1 to 24 and ILB 1 to 5 Mature Prior to 2028							
24	**Green Bond 1**		417.1	6/22/2018	29.9	6/22/2048	3.92%	16.3
25	**Green Bond 2**		0.4	1/18/2019	29.9	1/18/2049	4.34%	0.0
26	**Green Bond 3**		297.9	7/18/2022	10.0	7/19/2032	5.08%	15.1
27	**ILB 6**		25.0	1/5/2027	5.0	1/5/2032	7.08%	1.8
28	**Green Bond 4**		496.7	6/28/2024	10.0	6/28/2034	4.98%	24.7
29	**Green Bond 5**		491.0	6/28/2024	29.9	6/28/2054	5.17%	25.4
30	**Green Bond 6**		209.0	9/11/2024	9.8	6/28/2034	4.43%	9.3
31	**Green Bond 7**		104.1	9/11/2024	29.7	6/28/2054	4.85%	5.1
32	**Green Bond 8**		496.8	3/13/2025	10.0	3/13/2035	4.45%	22.1
33	**Green Bond 9**		496.3	3/13/2025	29.9	3/13/2055	4.97%	24.7
34	**Total**		**3,034.3**				**4.76%**	**144.4**
	Total Regulated Funded Long-Term Debt							
35	Line 23+34		**8,335.3**				**4.78%**	**398.8**

See Ex. C1-1-2 Table 10a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 10a
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2028
Notes to Ex. C1-1-2, Table 10

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Issue 44	3/15/2028	405	292	323.1
Note 2	Issue 45	3/15/2028	405	292	323.1
Note 3	Issue 46	6/15/2028	405	200	221.3
Note 4	Issue 47	6/15/2028	405	200	221.3
Note 5	Issue 48	9/15/2028	405	108	119.5
Note 6	Issue 49	9/15/2028	400	108	118.0
	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)

Note 7 Allocation ratio as per Ex. C1-1-2 Table 1, line 13, col (e).

Note 8 Future issue rate reference Bloomberg (Nov 21, 2025).

Issue 44

GOC & OPG Spread	
GOC Q1-28	3.42%
OPG Spread	1.35%
Issuance Cost	0.12%
Effective Rate	4.89%

Issue 45

GOC & OPG Spread	
GOC Q1-28	3.65%
OPG Spread	1.60%
Issuance Cost	0.10%
Effective Rate	5.35%

Issue 46

GOC & OPG Spread	
GOC Q2-28	3.53%
OPG Spread	1.35%
Issuance Cost	0.12%
Effective Rate	5.00%

Issue 47

GOC & OPG Spread	
GOC Q2-28	3.77%
OPG Spread	1.60%
Issuance Cost	0.10%
Effective Rate	5.47%

Issue 48

GOC & OPG Spread	
GOC Q3-28	3.56%
OPG Spread	1.35%
Issuance Cost	0.12%
Effective Rate	5.03%

Issue 49

GOC & OPG Spread	
GOC Q3-28	3.78%
OPG Spread	1.60%
Issuance Cost	0.10%
Effective Rate	5.48%

Table 11
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2029

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 to 25, 29, 35, 39 Mature Prior to 2029							
1	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
2	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
3	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
4	**Issue 30**		50.0	11/22/2016	30.0	11/22/2046	4.03%	2.0
5	**Issue 31**		200.0	2/22/2017	30.0	2/22/2047	4.12%	8.2
6	**Issue 32**		100.0	6/22/2017	30.0	6/22/2047	3.65%	3.6
7	**Issue 33**		100.0	8/22/2017	30.0	8/22/2047	3.86%	3.9
8	**Issue 34**		400.0	9/22/2017	30.0	9/22/2047	4.07%	16.3
9	**Issue 36**		200.0	1/22/2018	30.0	1/22/2048	3.87%	7.7
10	**Issue 37**		400.0	3/22/2018	30.0	3/22/2048	4.00%	16.0
11	**Issue 38**		100.0	8/22/2019	20.0	8/22/2039	3.49%	3.5
12	**Issue 40**		580.0	3/15/2027	10.0	3/15/2037	4.84%	28.1
13	**Issue 41**		580.0	3/15/2027	30.0	3/15/2057	5.41%	31.4
14	**Issue 42**		580.0	9/15/2027	10.0	9/15/2037	4.89%	28.4
15	**Issue 43**		580.0	9/15/2027	30.0	9/15/2057	5.45%	31.6
16	**Issue 44**		405.0	3/15/2028	10.0	3/15/2038	4.89%	19.8
17	**Issue 45**		405.0	3/15/2028	30.0	3/15/2058	5.35%	21.7
18	**Issue 46**		405.0	6/15/2028	10.0	6/15/2038	5.00%	20.3
19	**Issue 47**		405.0	6/15/2028	30.0	6/15/2058	5.47%	22.2
20	**Issue 48**		405.0	9/15/2028	10.0	9/15/2038	5.03%	20.4
21	**Issue 49**		400.0	9/15/2028	30.0	9/15/2058	5.48%	21.9
22	**Issue 50**	1, 8	420.0	3/15/2029	10.0	3/15/2039	5.08%	21.3
23	**Issue 51**	2, 8	420.0	3/15/2029	30.0	3/15/2059	5.50%	23.1
24	**Issue 52**	3, 8	287.7	6/15/2029	10.0	6/15/2039	5.10%	14.7
25	**Issue 53**	4, 8	284.9	6/15/2029	30.0	6/15/2059	5.51%	15.7
26	**Issue 54**	5, 8	153.9	9/15/2029	10.0	9/15/2039	5.13%	7.9
27	**Issue 55**	6, 8	153.9	9/15/2029	30.0	9/15/2059	5.51%	8.5
28	**Total**		**8,515.3**				**4.96%**	**421.9**
	Regulated Portion of Company-Wide Borrowing							
29	**Allocation**	7	7,924.1				4.96%	392.6
	Project Financing - Regulated Projects							
	Niagara 1 to 24, and ILB 1 to 5 Mature Prior to 2029							
30	**Green Bond 1**		417.1	6/22/2018	30.0	6/22/2048	3.92%	16.3
31	**Green Bond 2**		0.4	1/18/2019	30.0	1/18/2049	4.34%	0.0
32	**Green Bond 3**		297.9	7/18/2022	10.0	7/19/2032	5.08%	15.1
33	**ILB 6**		25.0	1/5/2027	5.0	1/5/2032	7.08%	1.8
34	**Green Bond 4**		496.7	6/28/2024	10.0	6/28/2034	4.98%	24.7
35	**Green Bond 5**		491.0	6/28/2024	30.0	6/28/2054	5.17%	25.4
36	**Green Bond 6**		209.0	9/11/2024	9.8	6/28/2034	4.43%	9.3
37	**Green Bond 7**		104.1	9/11/2024	29.8	6/28/2054	4.85%	5.1
38	**Green Bond 8**		496.8	3/13/2025	10.0	3/13/2035	4.45%	22.1
39	**Green Bond 9**		496.3	3/13/2025	30.0	3/13/2055	4.97%	24.7
40	**Total**		**3,034.3**				**4.76%**	**144.4**
	Total Regulated Funded Long-Term Debt							
41	Line 29+40		**10,958.5**				**4.90%**	**537.1**

See Ex. C1-1-2 Table 11a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Numbers may not add due to rounding.

Table 11a
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2029
Notes to Ex. C1-1-2, Table 11

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Issue 50	3/15/2029	525	292	420.0
Note 2	Issue 51	3/15/2029	525	292	420.0
Note 3	Issue 52	6/15/2029	525	200	287.7
Note 4	Issue 53	6/15/2029	520	200	284.9
Note 5	Issue 54	9/15/2029	520	108	153.9
Note 6	Issue 55	9/15/2029	520	108	153.9
	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)

Note 7 Allocation ratio as per Ex. C1-1-2 Table 1, line 13, col (e).

Note 8 Future issue rate reference Bloomberg (Nov 21, 2025).

Issue 50

GOC & OPG Spread	
GOC Q1-29	3.61%
OPG Spread	1.35%
Issuance Cost	0.12%
Effective Rate	5.08%

Issue 51

GOC & OPG Spread	
GOC Q1-29	3.80%
OPG Spread	1.60%
Issuance Cost	0.10%
Effective Rate	5.50%

Issue 52

GOC & OPG Spread	
GOC Q2-29	3.63%
OPG Spread	1.35%
Issuance Cost	0.12%
Effective Rate	5.10%

Issue 53

GOC & OPG Spread	
GOC Q2-29	3.81%
OPG Spread	1.60%
Issuance Cost	0.10%
Effective Rate	5.51%

Issue 54

GOC & OPG Spread	
GOC Q3-29	3.66%
OPG Spread	1.35%
Issuance Cost	0.12%
Effective Rate	5.13%

Issue 55

GOC & OPG Spread	
GOC Q3-29	3.81%
OPG Spread	1.60%
Issuance Cost	0.10%
Effective Rate	5.51%

Table 12
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2030

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 to 25, 29, 35, 39 Mature Prior to 2030							
1	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
2	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
3	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
4	**Issue 30**		50.0	11/22/2016	30.0	11/22/2046	4.03%	2.0
5	**Issue 31**		200.0	2/22/2017	30.0	2/22/2047	4.12%	8.2
6	**Issue 32**		100.0	6/22/2017	30.0	6/22/2047	3.65%	3.6
7	**Issue 33**		100.0	8/22/2017	30.0	8/22/2047	3.86%	3.9
8	**Issue 34**		400.0	9/22/2017	30.0	9/22/2047	4.07%	16.3
9	**Issue 36**		200.0	1/22/2018	30.0	1/22/2048	3.87%	7.7
10	**Issue 37**		400.0	3/22/2018	30.0	3/22/2048	4.00%	16.0
11	**Issue 38**		100.0	8/22/2019	20.0	8/22/2039	3.49%	3.5
12	**Issue 40**		580.0	3/15/2027	10.0	3/15/2037	4.84%	28.1
13	**Issue 41**		580.0	3/15/2027	30.0	3/15/2057	5.41%	31.4
14	**Issue 42**		580.0	9/15/2027	10.0	9/15/2037	4.89%	28.4
15	**Issue 43**		580.0	9/15/2027	30.0	9/15/2057	5.45%	31.6
16	**Issue 44**		405.0	3/15/2028	10.0	3/15/2038	4.89%	19.8
17	**Issue 45**		405.0	3/15/2028	30.0	3/15/2058	5.35%	21.7
18	**Issue 46**		405.0	6/15/2028	10.0	6/15/2038	5.00%	20.3
19	**Issue 47**		405.0	6/15/2028	30.0	6/15/2058	5.47%	22.2
20	**Issue 48**		405.0	9/15/2028	10.0	9/15/2038	5.03%	20.4
21	**Issue 49**		400.0	9/15/2028	30.0	9/15/2058	5.48%	21.9
22	**Issue 50**		525.0	3/15/2029	10.0	3/15/2039	5.08%	26.7
23	**Issue 51**		525.0	3/15/2029	30.0	3/15/2059	5.50%	28.9
24	**Issue 52**		525.0	6/15/2029	10.0	6/15/2039	5.10%	26.8
25	**Issue 53**		520.0	6/15/2029	30.0	6/15/2059	5.51%	28.7
26	**Issue 54**		520.0	9/15/2029	10.0	9/15/2039	5.13%	26.7
27	**Issue 55**		520.0	9/15/2029	30.0	9/15/2059	5.51%	28.7
28	**Issue 56**	1, 4	361.6	6/15/2030	10.0	6/15/2040	5.19%	18.8
29	**Issue 57**	2, 4	361.6	6/15/2030	30.0	6/15/2060	5.53%	20.0
30	**Total**		**10,653.3**				**5.03%**	**535.8**
	Regulated Portion of Company-Wide Borrowing							
31	**Allocation**	3	9,913.7				5.03%	498.6
	Project Financing - Regulated Projects							
	Niagara 1 to 24, and ILB 1 to 5 Mature Prior to 2030							
32	**Green Bond 1**		417.1	6/22/2018	30.0	6/22/2048	3.92%	16.3
33	**Green Bond 2**		0.4	1/18/2019	30.0	1/18/2049	4.34%	0.0
34	**Green Bond 3**		297.9	7/18/2022	10.0	7/19/2032	5.08%	15.1
35	**ILB 6**		25.0	1/5/2027	5.0	1/5/2032	7.08%	1.8
36	**Green Bond 4**		496.7	6/28/2024	10.0	6/28/2034	4.98%	24.7
37	**Green Bond 5**		491.0	6/28/2024	30.0	6/28/2054	5.17%	25.4
38	**Green Bond 6**		209.0	9/11/2024	9.8	6/28/2034	4.43%	9.3
39	**Green Bond 7**		104.1	9/11/2024	29.8	6/28/2054	4.85%	5.1
40	**Green Bond 8**		496.8	3/13/2025	10.0	3/13/2035	4.45%	22.1
41	**Green Bond 9**		496.3	3/13/2025	30.0	3/13/2055	4.97%	24.7
42	**Total**		**3,034.3**				**4.76%**	**144.4**
	Total Regulated Funded Long-Term Debt							
43	Line 31+42		**12,948.0**				**4.97%**	**643.1**

See Ex. C1-1-2 Table 12a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 12a
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2030
Notes to Ex. C1-1-2, Table 12

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
Note 1	Issue 56	6/15/2030	660	200	361.6
Note 2	Issue 57	6/15/2030	660	200	361.6
	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)

Note 3 Allocation ratio as per Ex. C1-1-2 Table 1, line 13, col (e).

Note 4 Future issue rate reference Bloomberg (Nov 21, 2025).

Issue 56

GOC & OPG Spread	
GOC Q2-30	3.72%
OPG Spread	1.35%
Issuance Cost	0.12%
Effective Rate	5.19%

Issue 57

GOC & OPG Spread	
GOC Q2-30	3.83%
OPG Spread	1.60%
Issuance Cost	0.10%
Effective Rate	5.53%

Table 13
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2031

Line No.	Issue	Note	Weighted Principal* ($M)	Issue Date	Duration (years)	Maturity Date	Effective Rate (%)	Annual Cost ($M)
			(a)	(b)	(c)	(d)	(e)	(f)
	Company-Wide Borrowing							
	Issues 1 to 25, 29, 35, 39 Mature Prior to 2031							
1	**Issue 26**		150.0	3/22/2011	30.0	3/22/2041	5.40%	8.1
2	**Issue 27**		150.0	9/22/2011	30.0	9/22/2041	4.74%	7.1
3	**Issue 28**		200.0	3/22/2012	30.0	3/22/2042	4.36%	8.7
4	**Issue 30**		50.0	11/22/2016	30.0	11/22/2046	4.03%	2.0
5	**Issue 31**		200.0	2/22/2017	30.0	2/22/2047	4.12%	8.2
6	**Issue 32**		100.0	6/22/2017	30.0	6/22/2047	3.65%	3.6
7	**Issue 33**		100.0	8/22/2017	30.0	8/22/2047	3.86%	3.9
8	**Issue 34**		400.0	9/22/2017	30.0	9/22/2047	4.07%	16.3
9	**Issue 36**		200.0	1/22/2018	30.0	1/22/2048	3.87%	7.7
10	**Issue 37**		400.0	3/22/2018	30.0	3/22/2048	4.00%	16.0
11	**Issue 38**		100.0	8/22/2019	20.0	8/22/2039	3.49%	3.5
12	**Issue 40**		580.0	3/15/2027	10.0	3/15/2037	4.84%	28.1
13	**Issue 41**		580.0	3/15/2027	30.0	3/15/2057	5.41%	31.4
14	**Issue 42**		580.0	9/15/2027	10.0	9/15/2037	4.89%	28.4
15	**Issue 43**		580.0	9/15/2027	30.0	9/15/2057	5.45%	31.6
16	**Issue 44**		405.0	3/15/2028	10.0	3/15/2038	4.89%	19.8
17	**Issue 45**		405.0	3/15/2028	30.0	3/15/2058	5.35%	21.7
18	**Issue 46**		405.0	6/15/2028	10.0	6/15/2038	5.00%	20.3
19	**Issue 47**		405.0	6/15/2028	30.0	6/15/2058	5.47%	22.2
20	**Issue 48**		405.0	9/15/2028	10.0	9/15/2038	5.03%	20.4
21	**Issue 49**		400.0	9/15/2028	30.0	9/15/2058	5.48%	21.9
22	**Issue 50**		525.0	3/15/2029	10.0	3/15/2039	5.08%	26.7
23	**Issue 51**		525.0	3/15/2029	30.0	3/15/2059	5.50%	28.9
24	**Issue 52**		525.0	6/15/2029	10.0	6/15/2039	5.10%	26.8
25	**Issue 53**		520.0	6/15/2029	30.0	6/15/2059	5.51%	28.7
26	**Issue 54**		520.0	9/15/2029	10.0	9/15/2039	5.13%	26.7
27	**Issue 55**		520.0	9/15/2029	30.0	9/15/2059	5.51%	28.7
28	**Issue 56**		660.0	6/15/2030	10.0	6/15/2040	5.19%	34.3
29	**Issue 57**		660.0	6/15/2030	30.0	6/15/2060	5.53%	36.5
30	**Total**		**11,250.0**				**5.05%**	**567.8**
	Regulated Portion of Company-Wide Borrowing							
31	**Allocation**	1	10,469.0				5.05%	528.4
	Project Financing - Regulated Projects							
	Niagara 1 to 24, and ILB 1 to 5 Mature Prior to 2031							
32	**Green Bond 1**		417.1	6/22/2018	30.0	6/22/2048	3.92%	16.3
33	**Green Bond 2**		0.4	1/18/2019	30.0	1/18/2049	4.34%	0.0
34	**Green Bond 3**		297.9	7/18/2022	10.0	7/19/2032	5.08%	15.1
35	**ILB 6**		25.0	1/5/2027	5.0	1/5/2032	7.08%	1.8
36	**Green Bond 4**		496.7	6/28/2024	10.0	6/28/2034	4.98%	24.7
37	**Green Bond 5**		491.0	6/28/2024	30.0	6/28/2054	5.17%	25.4
38	**Green Bond 6**		209.0	9/11/2024	9.8	6/28/2034	4.43%	9.3
39	**Green Bond 7**		104.1	9/11/2024	29.8	6/28/2054	4.85%	5.1
40	**Green Bond 8**		496.8	3/13/2025	10.0	3/13/2035	4.45%	22.1
41	**Green Bond 9**		496.3	3/13/2025	30.0	3/13/2055	4.97%	24.7
42	**Total**		**3,034.3**				**4.76%**	**144.4**
	Total Regulated Funded Long-Term Debt							
43	Line 31+42		**13,503.3**				**4.98%**	**672.8**

See Ex. C1-1-2 Table 12a for notes

* For debt issues that are issued or mature during the year the face value is reduced to reflect only that portion of the year the debt issue is financing the rate base.

Table 13a
Capitalization and Cost of Capital
Summary of Existing and Planned Long-Term Debt - OPG ($M)
Outstanding During Calendar Year Ending Dec. 31, 2031
Notes to Ex. C1-1-2, Table 13

	Issue	Issue Date	Face Value ($M)	Effective Days	Weighted Principal ($M)
	Issue	Maturity Date	Face Value ($M)	Effective Days	Weighted Principal ($M)

Note 1 Allocation ratio as per Ex. C1-1-2 Table 1, line 13, col (e).

OPG'S COST OF SHORT-TERM DEBT

1.0 PURPOSE

This evidence details OPG's annual short-term borrowing and associated costs for OPG's regulated operations for the bridge years and IR term that are reflected in the proposed capitalization of OPG's rate base. It also provides actual short-term debt costs for 2020-2024.

2.0 DESCRIPTION OF SHORT-TERM DEBT

As in prior OPG applications, the short-term debt component of OPG's capital structure reflects its forecast amount of corporate short-term borrowings, and the cost of short-term debt reflects OPG's forecast of the corporate short-term borrowing cost. The summary of capitalization for the IR term is provided in Ex. C1-1-1, Tables 1-12 for OPG's regulated operations.

OPG's corporate short-term debt is comprised of a CAD and a USD commercial paper program, backstopped by credit facilities. OPG currently has a bank-syndicated committed credit facility with a CAD$1B credit limit and a USD$750M credit limit. OPG also continues to have access to the Ontario Electricity Financial Corporation ("OEFC") credit facility, which currently has an undrawn capacity of $750M and, since December 2024, maintains a $1.25B credit facility with the Ontario Financing Authority ("OFA"). In addition to being used as a backstop to the commercial paper programs, the above credit facilities provide liquidity support in the event that OPG is unable to issue either short-term or long-term wholesale unsecured funding (such as commercial paper or long-term bonds) if there were to be a systematic market disruption.

Further, as part of the credit rating agencies' assessments, OPG is required to have sources of liquidity that meet projected uses of liquidity over a 12-18 month horizon, where such uses of liquidity include capital expenditures and debt maturities. With the company's increasing project expenditures, the above credit facilities are therefore also necessary to ensure OPG can meet credit agencies' liquidity expectations in support of current credit ratings.

The methodology to determine the regulated portion of forecast corporate short-term debt was accepted by the OEB in previous payment amounts proceedings. OPG has made modifications to the application of the previously used methodology to determine the forecast cost of short-term debt, as discussed in Section 4.0 below.

3.0 SHORT-TERM DEBT COST

OPG's borrowing rate under its commercial paper programs is market-based and comprises three components determined at the time of issuances: i) a benchmark "risk-free" rate, ii) a corporate spread, which is analogous to the credit spread on long-term debt, and iii) a 10-basis point dealer fee. As in prior OPG payment amounts proceedings, the cost of forecast short-term debt over the 2026-2031 period is based on a forecast of a benchmark "risk-free" rate and an observed OPG corporate spread.

OPG has made the following updates to the application of the above methodology to determine the cost of its short-term debt in this Application, compared to previous proceedings:

- Historically, IHS Markit's Global Insight Economics ("Global Insight") was used as a third-party market source. In this application, OPG has adopted a revised data source consistent with a similar change made for forecasting the long-term debt rates (see Ex. C1-1-2).
- As a replacement source of forecast information covering the IR term, OPG is utilizing an 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.[1] Bloomberg forecasts currently do not extend beyond 2028 since many economists are not publishing forecasts beyond two years, given the current uncertainty in the global economy. To create a more continuous forecast over the seven-year period, for the years where the Bloomberg Bond Yield Median Forecast was not available, OPG inferred such forecast 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.
- 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

[1] Survey as of November 21, 2025.

over the OIS rate observed since the OIS became the benchmark for commercial paper rates in mid-2024. This 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. The resulting corporate spread is 17 basis points over the OIS rate.

The bank credit facility fees are forecast to cost an average of $8.7M annually between 2027-2031. The increase in fees compared to the historical years is primarily due to the addition of the $1.25B credit facility with the OFA in December 2024, as well as anticipated future facility needs to meet the liquidity requirements set by the credit rating agencies. As in prior payment amounts applications, these costs are included with OPG's short-term debt costs.

Exhibit C1-1-3, Table 2 summarizes OPG's forecasted company-wide cost of short-term debt.

4.0 ALLOCATION TO REGULATED OPERATIONS

For the IR term, OPG has used the same allocation methodology accepted by the OEB in prior payment amount proceedings to allocate company-wide short-term debt to the regulated operations. In summary, the ratio of the construction work in progress and non-cash working capital amounts (fuel inventory and materials/supplies) for OPG's regulated operations to the total construction work in progress and non-cash working capital amounts reported in OPG's audited consolidated financial statements is used as the basis for allocating company-wide short-term borrowing. This allocation ratio reflects OPG's use of short-term borrowing to finance its working capital requirements and to assist with managing the cash-flow variability associated with capital projects.

For all company-wide short-term borrowing up to December 31, 2024 the allocation ratio is determined based on actual year-end values for the corresponding years. Consistent with the approach applied in prior payment amounts proceedings and for the allocation of the long-term debt (Ex. C1-1-2, Section 3.2), OPG has used information from its most recent available audited financial statements (2024) to determine the allocation factor for 2025-2031. The allocation ratios are calculated in Ex. C1-1-3, Table 1.

Table 1
Capitalization and Cost of Capital
Allocation of Existing Short-term Debt - OPG ($M)

Line No.	Asset	Note	Amount 2020	2021	2022	2023	2024
			(a)	(b)	(c)	(d)	(e)
	Company-Wide:						
1	**Construction Work-In-Progress (CWIP)**	1	2,339.3	3,567.9	4,619.2	3,946.0	4,373.3
2	**CWIP Using Short-term Project Financing**		0.0	0.0	0.0	0.0	0.0
3	**Fuel**		235.6	247.3	251.9	295.4	297.0
4	**Materials/Supplies**		495.9	516.3	502.8	487.7	499.7
5	**CWIP + Non Cash Working Capital**		3,070.8	4,331.6	5,373.9	4,729.1	5,170.0
	Regulated Operations:						
6	**Construction Work-In-Progress (CWIP)**	2	2,116.2	3,095.1	4,170.0	3,349.8	3,555.6
7	**Fuel**	3	190.3	201.4	192.0	242.9	233.1
8	**Materials/Supplies**	4	492.7	513.6	499.3	484.3	495.6
9	**CWIP + Non Cash Working Capital**		2,799.2	3,810.1	4,861.3	4,077.0	4,284.3
10	**Total Regulated/Company-Wide CWIP + Non Cash Working Capital** (line 9/ line 5)		91.2%	88.0%	90.5%	86.2%	82.9%

Notes:

1 From Ex. C1-1-2 Table 1, line 2.
2 From Ex. C1-1-2 Table 1, line 8
3 From Ex. B3-5-1 Table 1, col. (b).
4 Sum of Ex. B2-5-1, Table 2, col. (b) for Regulated Hydroelectric, and Ex. B3-5-1 Table 1, col. (b) for OPG Nuclear, reflecting the closing balance in actual rate base.

Numbers may not add due to rounding.

Table 2
Capitalization and Cost of Capital
Summary of OPG's Actual and Forecast Cost of Short-term Debt ($M)

Line No.	Description	Note	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	**Commercial Paper Amount**	1	207.5	9.0	0.0	13.8	150.2	252.5	500.0	500.0	500.0	500.0	500.0	500.0
2	**Interest Rate**		0.70%	0.21%	0.79%	5.20%	4.79%	2.90%	2.47%	2.79%	2.93%	3.07%	3.22%	3.39%
3	**Commercial Paper Cost**		1.5	0.0	0.0	0.7	7.2	7.3	12.4	14.0	14.7	15.4	16.1	17.0
4	**Facility Cost**		3.7	5.2	4.0	4.1	4.1	7.1	7.1	11.4	8.9	8.9	7.1	7.1
5	**Total Short-term Debt Cost** (line 3 + line 4)		5.2	5.2	4.0	4.8	11.3	14.4	19.5	25.3	23.5	24.2	23.2	24.1
	Regulated Portion of Short-Term Debt													
6	**Allocation Factor**	2	91.2%	88.0%	90.5%	86.2%	82.9%	82.9%	82.9%	82.9%	82.9%	82.9%	82.9%	82.9%
7	**Short Term Debt Amount** (line 1 x line 6)		189.2	7.9	0.0	11.9	124.5	209.2	414.3	414.3	414.3	414.3	414.3	414.3
8	**Short-term Debt Cost** (line 5 x line 6)		4.7	4.6	3.6	4.2	9.4	12.0	16.1	21.0	19.5	20.1	19.2	19.9

Notes:
1 Actual daily weighted average balance shown for 2020 to 2024. Working Capital funding with commercial paper is assumed to be outstanding for the first 20 days of each month in the forecast period.
2 Allocation factor determined at Ex. C1-1-3 Table 1 line 10. The 2025-2031 allocation is based on 2024 actual allocation.