EXHIBIT LIST					
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A1	3	1		Summary of Application	2025-12-12
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			2	Empirical Analysis of Total Factor Productivity Trends in the North American Hydroelectric Generation Industry, London Economics International LLC	2025-12-12
			3	Benchmarking the Costs of Hydroelectric Generation Companies in North America, London Economics International LLC	2025-12-12
			4	2024 Hydroelectric Facilities Performance Scorecard	2025-12-12

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A1	4	1		Overview of OPG	2025-12-12
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			3	Memorandum of Agreement between the Shareholder and OPG	2025-12-12
			4	Summaries of Internal Audits Completed Since Q4 2020	2025-12-12
A1	4	2		Overview of Regulated Hydroelectric Facilities	2025-12-12
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A1	4	3		Overview of Nuclear Facilities	2025-12-12
A1	4	4		Overview of DNNP LP	2025-12-12
			1	DNNP LP 2026-2031 Business Plan	2026-01-19
A1	5	1		Corporate Organizational Chart	2025-12-12
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A1	12	1		List of Acronyms	2025-12-12
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			1	OPG's 2025 Third Quarter Interim Consolidated Financial Statements (unaudited) and Management's Discussion and Analysis	2025-12-12
			2	OPG's 2025 Second Quarter Interim Consolidated Financial Statements (unaudited) and Management's Discussion and Analysis	2025-12-12
			3	OPG's 2025 First Quarter Interim Consolidated Financial Statements (unaudited) and Management's Discussion and Analysis	2025-12-12

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			2	DBRS Morningstar, April 25, 2022	2025-12-12
			3	DBRS Morningstar, May 8, 2023	2025-12-12
			4	DBRS Morningstar, April 30, 2024	2025-12-12
			5	DBRS Morningstar, April 21, 2025	2025-12-12
			6	Moody's Investor Service, April 1, 2022	2025-12-12
			7	Moody's Investor Service, June 12, 2023	2025-12-12
			8	Moody's Investor Service, June 24, 2024	2025-12-12
			9	Moody's Investor Service, June 30, 2025	2025-12-12
			10	S&P Global Ratings, August 13, 2021	2025-12-12
			11	S&P Global Ratings, August 3, 2022	2025-12-12
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			2	Executed Engagement Letter for Concentric Energy Advisors	2025-12-12
			3	Initial Financing for Darlington New Nuclear Program Expert Testimony by Cliff Inskip	2025-12-12
			4	Executed Engagement Letter for Polar Star Advisory	2025-12-12
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D1	1	2		Capital Projects – Regulated Hydroelectric	2025-12-12
			1	Business Case Summaries and Supporting Information	2025-12-12
D2				**Nuclear**	
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			1	Project Lifecycle Phases and Gates	2025-12-12
D2	1	2		Capital Expenditures – Nuclear Operations	2025-12-12
D2	1	3		Capital Projects – Nuclear Operations	2025-12-12
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			2	Darlington Refurbishment Program 2020 Annual Report	2025-12-12
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			1	CNSC Regulatory Document REGDOC-2.3.3: Periodic Safety Reviews	2025-12-12
			2	Predictive Environmental Risk Assessment for Pickering Refurbishment, Decommissioning, and Continued Operations (P-REP-07701-00014)	2025-12-12
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D2	3	3		Pickering Refurbishment Program Major Work Bundle Structure and Contracts	2025-12-12
			1	Contract Summary for RFBR with Atkins/Aecon JV	2025-12-12
			2	Contract Summary for Turbine Generators with the TG Consortium	2025-12-12
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D2	3	4		Pickering Refurbishment Program Planning	2025-12-12
D2	3	5		Pickering Refurbishment Program Scope	2025-12-12
			1	Scope Differences Between Darlington Refurbishment and Pickering Refurbishment	2025-12-12
D2	3	6		Pickering Refurbishment Program Schedule	2025-12-12
			1	Pickering Refurbishment Outage Schedule – Level 1 Overview	2025-12-12
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			2	KPMG Report on RQE	2025-12-12
D2	3	9		Pickering Refurbishment Program Execution	2025-12-12
			1	Pickering Refurbishment Project Controls Program Management Plan – NK30-PLAN-00120-00003	2025-12-12
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			1	Pegasus Global Holdings, Inc. – Testimony of Joseph Miller	2026-01-19
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			1	Detailed Breakdown of Evidence Structure	2025-12-12
D2	4	2		Darlington New Nuclear Program Structure	2025-12-12
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			1	Detailed Description of DNNP Program Phases	2025-12-12
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D2	4	6		Darlington New Nuclear Program Schedule	2025-12-12
			1	Unit 1 Release Quality Estimate Project Working Schedule Diagram	2025-12-12
D2	4	7		Darlington New Nuclear Program Contingency	2025-12-12
D2	4	8		Darlington New Nuclear Program Costs and In-service Amounts	2025-12-12
			1	DNNP Unit 1 Execution Phase Funding Release and Units 2-4 Definition Phase Funding Release, March 2025	2025-12-12

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			1	OPG's 2024-2028 Technology Roadmap	2025-12-12
D3	1	2		Capital Projects – Support Services	2025-12-12
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			1	Regulated Stations with Modeled Production Forecasts	2025-12-12

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E1	2	1		HIM, SBG, MRP and MWP	2025-12-12
			1	Surplus Baseload Generation Variance Account Study	2025-12-12
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			1	Glossary of Outage and Generation Performance Terms	2025-12-12
E2	1	2		Comparison of Production Forecasts – Nuclear	2025-12-12
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F1	2	1		Base OM&A Costs – Regulated Hydroelectric	2025-12-12
			1	Renewable Generation Organizational Structure	2025-12-12
F1	2	2		Comparison of Base OM&A Costs – Regulated Hydroelectric	2025-12-12

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F2				**Nuclear**	
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			1	Prior Gap Closure Initiatives	2025-12-12
			2	OPG 2024 Nuclear Benchmarking Report	2025-12-12
			3	ScottMadden Evaluation of OPG Nuclear Benchmarking	2025-12-12
			4	OPG Nuclear Cost Performance Benchmarking – A Study of Factors Impacting TGC/MWH Performance with Normalizing Adjustments to Facilitate Closer Comparison (ScottMadden)	2025-12-12

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			6	ScottMadden Evaluation of OPG Nuclear Benchmarking Retainer Letter	2025-12-12
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F2	2	1		Nuclear Base and DNNP Operational Readiness OM&A Costs	2025-12-12
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F2	3	1		Project OM&A Costs – Nuclear	2025-12-12
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			1	Business Case Summaries for OM&A Projects > $20M or more	2025-12-12
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F2	4	2		Comparison of Nuclear Outage OM&A	2025-12-12
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F3	1	1		Allocation of Support Services Costs	2025-12-12
			1	Description of Corporate Support Functions	2025-12-12
			2	Benchmarking Study of OPG's Corporate Support Functions and Costs prepared by The Hackett Group	2025-12-12
F3	1	2		Comparison of Allocation of Support Services Costs	2025-12-12
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			1	Cost Allocation Review Ontario Power Generation by Elenchus Research Associates	2025-12-12
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F3	2	2		Comparison of Asset Service Fees	2025-12-12
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			2	2024 Depreciation Review Committee Recommendations for Nuclear	2025-12-12
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			4	2022 Depreciation Review Committee Recommendations for Nuclear	2025-12-12
			5	2021 Depreciation Review Committee Recommendations for Nuclear	2025-12-12
			6	2020 Depreciation Review Committee Recommendations for Nuclear	2025-12-12
			7	Concentric Report: Assessment of Regulated Hydroelectric Asset Depreciation Rates – November 2025	2025-12-12
			8	2024 Depreciation Review Committee Recommendations for Regulated Hydroelectric Generation	2025-12-12
			9	2023 Depreciation Review Committee Recommendations for Regulated Hydroelectric Generation	2025-12-12
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			12	Concentric Report: 2019 Assessment of Regulated Asset Depreciation Rates and Generating Station Lives – December 2019	2025-12-12
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			1	2024 Income Tax Returns and Notices	2025-12-12
F4	3	1		Compensation and Benefits	2025-12-12
			1	FTE, Compensation and Benefit Information for OPG's Nuclear Regulated Facilities ("Appendix 2k")	2025-12-12
			2	Southlea Report and Recommendations on OPG Compensation Philosophy	2025-12-12
			3	Total Compensation Benchmarking Study prepared by Willis Towers Watson	2025-12-12
			4	Comparison of Salary Schedules for Society and PWU Roles prepared by Willis Towers Watson	2025-12-12
			5	Benchmarking Tenure Analysis prepared by Willis Towers Watson	2025-12-12
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			4	Aon Report on the actuarial valuation as at January 1, 2025 for OPG's Pension Plan	2025-12-12
			5	Summary Appendices of the historical, bridge period and IR term, actual pension and OPEB accrual costs, compared to the OEB-approved expenses, and pension contributions and OPEB payments	2025-12-12
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			2	Schedule of Regulatory Balances as at December 31, 2024	2025-12-12
			3	Supporting Info for SBGVA Clearance re: EB-2023-0336, Ex. L-H-SEC-04, Attachment 1 (Excel only)	2025-12-12
			4	Supporting Info for SBGVA Clearance re: EB-2023-0336, Ex. L-H-SEC-05, Attachment 1 (Excel only)	2025-12-12
			5	Hydroelectric CRVA Revenue Requirement (Capital Component)	2025-12-12
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			8	Nuclear CRVA (Excluding DRP and PRP) Revenue Requirement (Capital Component)	2025-12-12
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			1	Revenue Requirement Work Form (Excel only)	2025-12-12
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I1	2	1		Regulated Hydroelectric Payment Amount	2025-12-12
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B3	B3-1-1 • Table 1 – Prescribed Facility Rate Base – Combined Nuclear, 2020-2025

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ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998;*

AND IN THE MATTER OF an Application by Ontario Power Generation Inc. and DNNP LP by its general partner, DNNP GP Inc. for an order or orders approving payment amounts for prescribed generating facilities commencing January 1, 2027.

APPLICATION

1. This Application includes an application brought by Ontario Power Generation Inc. ("OPG") and an application brought by DNNP LP by its general partner, DNNP GP Inc. for certain orders approving payment amounts for their respective prescribed facilities.

2. OPG is a corporation, incorporated under the *Ontario Business Corporations Act*, with its head office in the City of Oshawa. The principal business of OPG is the generation and sale of electricity in Ontario.

3. DNNP LP is a limited partnership formed under the laws of the Province of Ontario. The partnership was established to facilitate investment in the Darlington New Nuclear Program ("DNNP") facilities.

4. OPG is a prescribed generator under O. Reg. 53/05, s. 1. DNNP LP will be a prescribed generator subject to certain conditions set out in section 8 of *Ontario Regulation 53/05* ("O. Reg. 53/05").

5. OPG applies to the Ontario Energy Board ("OEB") pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* (the "Act"), for:

a. An order or orders setting the payment amount for the hydroelectric generating facilities (the "regulated hydroelectric facilities") for the period from January 1, 2027 through December 31, 2027, approving the hydroelectric Custom Price-cap Index to set annual hydroelectric payment amounts from January 1, 2028 through December 31, 2031, and approving a payment rider for the regulated hydroelectric facilities for the period from January 1, 2027 through December 31, 2031.

b. Other approvals as set out in Ex. A1-2-2.

6. OPG and DNNP LP jointly apply to the OEB pursuant to section 78.1 of the Act for:

a. An order or orders approving blended payment amounts for OPG's nuclear facilities and the DNNP facilities prescribed under O. Reg. 53/05 for the period from January 1, 2027 through December 31, 2031 and blended payment riders for OPG's nuclear facilities and the DNNP facilities for the period from January 1, 2027 until December 31, 2031. For the purposes of section 14(2) of O. Reg. 53/05, OPG and DNNP LP request that the OEB use the methodology described in Ex. A1-3-2 to approve annual revenue requirements for the nuclear facilities for the period January 1, 2027 to December 31, 2031.

b. Other approvals as set out in Ex. A1-2-2.

7. OPG seeks an order declaring the current payment amounts interim, effective January 1, 2027, if the order or orders approving payment amounts for the nuclear facilities are not implemented by January 1, 2027.

8. This Application is filed in accordance with the OEB's *Filing Requirements for Ontario Power Generation Inc.* (September 17, 2024).

9. The Application will be supported by written and oral evidence. The written evidence filed by OPG and DNNP LP may be supplemented or amended from time to time by OPG and DNNP LP prior to the OEB's final decision on the Application.

10. OPG and DNNP LP further apply to the OEB pursuant to the provisions of the Act and the OEB Rules of Practice and Procedure for such orders and directions as may be necessary in relation to the Application and the proper conduct of this proceeding.

11. The persons affected by this Application are all electricity consumers in Ontario. It is impractical to set out the names and addresses of the consumers because they are too numerous.

12. OPG and DNNP LP request that copies of all documents filed with the OEB by each party to this Application along with copies of all comments filed with the OEB in accordance with Rule 24 of the OEB Rules of Practice and Procedure be served on the applicant and the applicant's counsel as follows:

(a)

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Dated at Toronto, Ontario, this 12th day of December, 2025.

Ontario Power Generation Inc.

[Original signed by:]

Charles Keizer

Torys LLP

APPROVALS

This Application seeks the following specific approvals:

Revenue Requirement

1. Approval of the 2027 revenue requirement for the regulated hydroelectric facilities of $1,668.3M, as set out in Ex. I1-1-1.

2. Approval of the following revenue requirements for OPG's nuclear facilities, net of the nuclear stretch factor, as set out in Ex. I1-1-1:

Period	Revenue Requirement
January 1, 2027 through December 31, 2027	$4,062.8M
January 1, 2028 through December 31, 2028	$4,257.3M
January 1, 2029 through December 31, 2029	$4,676.5M
January 1, 2030 through December 31, 2030	$4,881.7M
January 1, 2031 through December 31, 2031	$5,736.9M

3. Approval of the following revenue requirements for the Darlington New Nuclear Program ("DNNP") facilities, as set out in Ex. I1-1-1:

Period	Revenue Requirement
January 1, 2027 through December 31, 2027	$302.0M
January 1, 2028 through December 31, 2028	$381.4M
January 1, 2029 through December 31, 2029	$417.0M
January 1, 2030 through December 31, 2030	$582.1M
January 1, 2031 through December 31, 2031	$1,076.1M

Rate Base

4. Approval of a 2027 rate base for the prescribed hydroelectric facilities of $9,135.1M as summarized in Ex. B1-1-1.

5. Approval of the following rate bases for OPG's nuclear facilities, as summarized in Ex. B1-1-1:

Year	Rate Base
2027	$15,794.7M
2028	$16,328.3M
2029	$16,265.0M
2030	$16,867.5M
2031	$23,587.9M

6. Approval of the following rate bases for the DNNP facilities, as summarized in Ex. B1-1-1:

Year	Rate Base
2027	$0.0
2028	$0.0
2029	$2.1M
2030	$1,371.1M
2031	$6,530.0M

Production Forecasts

7. Approval of a production forecast of 32.5 TWh for 2027 for the prescribed hydroelectric facilities, as presented in Ex. E1-1-1.

8. Approval of the following production forecasts for OPG's nuclear facilities, as presented in Ex. E2-1-1.

Year	Production Forecast (TWh)
2027	18.7
2028	26.7
2029	25.1
2030	26.8
2031	28.9

9. Approval of the following production forecasts for the DNNP facilities, as presented in Ex. E2-1-1.

Year	Production Forecast (TWh)
2027	0.0
2028	0.0
2029	0.0
2030	0.5
2031	1.9

Cost of Capital

10. For OPG, approval of a deemed capital structure of 52% equity and 48% debt and a combined rate of return on rate base to be determined in accordance with the OEB's prevailing Return on Equity ("ROE") as of the effective date of the Payment Amounts Order, as presented in Ex. C1-1-1.

11. For the DNNP facilities, approval of a deemed capital structure that is 100% equity funded and a rate of return on rate base to be determined in accordance with the OEB's prevailing ROE as of the effective date of the Payment Amounts Order, as presented in Ex. C1-1-1.

Payment Amounts

12. Effective January 1, 2027, approval of a payment amount of $51.39/MWh for the average hourly net energy production (MWh) from the regulated hydroelectric facilities in any given day for each hour of that day, as set out in Ex. I1-2-1.

13. Approval to adjust OPG's revenues from the hydroelectric payment amount by the following hydroelectric incentive mechanism in any given day for each hour of that day:

    For the resource(s) at regulated hydroelectric facilities, for each hour where the IESO day-ahead market energy schedule (the "Day-Ahead Energy Schedule") differs from the average hourly energy schedule from the IESO's day-ahead market for that day (the "Average Day-Ahead Energy Schedule"), OPG's revenues will be adjusted by the difference between the Day-Ahead Energy Schedule and the Average Day-Ahead Energy Schedule, multiplied by the day-ahead locational marginal price for the resource for that hour. For the resource(s) at regulated hydroelectric facilities, for each hour where (i) the difference between the net energy production supplied to the IESO's real-time market and the Day-Ahead Energy Schedule ("Real-Time Energy Difference") differs from (ii) the difference between the average hourly net energy production over that day and the Average Day-Ahead Energy Schedule for that day ("Average Real-Time Energy Difference"), OPG's revenues will be adjusted by the difference between the Real-Time Energy Difference and the Average Real-Time Energy Difference, multiplied by the real-time locational marginal price for the resource for that hour, calculated on a five-minute basis.

14. Approval of the hydroelectric Custom Price-cap Index that the OEB will use to set hydroelectric payment amounts from January 1, 2028 through December 31, 2031, including the following Custom Capital Factor values, as set out in Ex. A1-3-2:

Effective Date	Custom Capital Factor
January 1, 2028	4.3%
January 1, 2029	5.0%
January 1, 2030	2.0%
January 1, 2031	0.8%

15. Approval of the following blended payment amounts for OPG's nuclear facilities and the DNNP facilities and the nuclear Custom IR framework as set out in Ex. A1-3-2 and I1-3-1:

Effective Date	Payment Amount
January 1, 2027	$206.76/MWh
January 1, 2028	$192.52/MWh
January 1, 2029	$203.20/MWh
January 1, 2030	$199.97/MWh
January 1, 2031	$220.68/MWh

Market Renewal Impacts

16. Approval to continue to book amounts in the Hydroelectric Surplus Baseload Generation Variance Account based on the revised local and global Surplus Baseload Generation spill methodology, as described in Ex. E1-2-1, Section 4.0.

17. Approval to continue the revised Hydroelectric Incentive Mechanism adjustment for spill ("unintended benefit") as described in Ex. E1-2-1, Section 5.0.

18. Approval to continue to retain Real-Time Energy Make Whole Payments as described in Ex. E1-2-1, Section 6.0.

Payment Amount Shaping

19. Approval of the payment amount shaping proposal as set out in Ex. I1-3-2, including the portion of the approved revenue requirement for OPG's nuclear facilities that is to be recorded in the Payment Amount Shaping Deferral Account. Specifically, OPG proposes to defer $500M of its proposed 2027 nuclear revenue requirement to 2028, with resulting Payment Amount Shaping Deferral Account entries of $500M in 2027, $-500M in 2028, $0 in 2029, $0 in 2030, and $0 in 2031.

Deferral and Variance Accounts and Riders

20. Approval for recovery and repayment of audited December 31, 2024 balances of the deferral and variance accounts for the regulated hydroelectric facilities and nuclear facilities as identified in Ex. H1-1-1 and Ex. H1-2-1.

21. Approval to continue existing deferral and variance accounts, including application of interest, as proposed in Ex. H1-1-1.

22. Approval to establish the following deferral and variance accounts as described in Ex. H1-1-1:
    i. Global Hydroelectric Capital Variance Account
    ii. Clean Electricity ITC Variance Account (OPG)
    iii. DNNP Nuclear Liability Deferral Account
    iv. Payment Amount Shaping Deferral Account
    v. Change of Laws Deferral Account (OPG)

23. For the DNNP facilities, approval to establish the following deferral and variance accounts as described in Ex. H1-1-1:
    i. Income and Other Taxes Variance Account (DNNP)
    ii. Pension and OPEB Cost Variance Account (DNNP)
    iii. Nuclear Deferral and Variance Over/Under Recovery Variance Account (DNNP)
    iv. SR&ED ITC Variance Account (DNNP)
    v. Impact for IFRS Deferral Account (DNNP)
    vi. Clean Electricity ITC Variance Account (DNNP)
    vii. Impact of Change in Tax Status Variance Account (DNNP)
    viii. Change of Laws Deferral Account (DNNP)

24. Approval of the annual process by which OPG proposes to recover balances of the Darlington New Nuclear Project Variance Account re Capital Cost Amounts and the Pickering B Refurbishment Project Variance Account, as required by O. Reg. 53/05, beginning with the recovery of 2026 balances during 2027.

25. Approval of a hydroelectric payment rider to recover and repay the audited December 31, 2024 balances in the deferral and variance accounts, less amortization amounts previously approved by the OEB in EB-2020-0290 (for 2025-2026) and EB-2023-0336 (for 2025-2026), together with the income tax impacts associated with the recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, at the following rates, applied to the output from the hydroelectric facilities:

Effective Date	**Payment Amount**
January 1, 2027	$(1.17)/MWh
January 1, 2028	$(1.17)/MWh
January 1, 2029	$(1.17)/MWh
January 1, 2030	$0.00/MWh
January 1, 2031	$0.00/MWh

26. Approval of a blended nuclear payment amount rider for OPG's nuclear facilities and the DNNP facilities to recover and repay the audited December 31, 2024 balances in the deferral and variance accounts, less amortization amounts previously approved by the OEB in EB-2020-0290 (for 2025-2026) and EB-2023-0336 (for 2025-2026), together with the income tax impacts associated with the recovery of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, applied to the combined output from OPG's nuclear facilities and the DNNP facilities:

Effective Date	Payment Amount
January 1, 2027	$7.19/MWh
January 1, 2028	$5.04/MWh
January 1, 2029	$5.36/MWh
January 1, 2030	$2.48/MWh
January 1, 2031	$2.19/MWh

Project Approvals

27. OPG seeks the following approvals for the DNNP:
    i. In-service additions to DNNP facilities' rate base of $6,585M in 2030 on a forecast basis. If actual additions to rate base or their timing are different from forecast amounts and their timing, the revenue requirement impact of the difference will be recorded in the Darlington New Nuclear Project Variance Account re Development and any amounts greater than the forecast amounts added to rate base will be subject to a prudence review in a future proceeding;
    ii. DNNP Concurrent Cost Recovery ("CCR") interest amounts on a forecast basis of $214.9M in 2027, $284.8M in 2028, $321.2M in 2029, $274.2M in 2030, and $24.6M in 2031, as described in Ex. I1-1-3 and calculated in Ex. I1-1-1, Table 6.[1]

[1] These amounts are included in the revenue requirement sought for approval in paragraph 3 above.

28. OPG seeks the following approvals for the Pickering Refurbishment Program ("PRP"):

    i. In-service additions to rate base of: (i) $159.3M in the 2026 bridge year; and (ii) for the IR term, $20.6M in 2027; $0.0M in 2028; $0.0M in 2029, $0.0M in 2030, and $9,688.0M in 2031, all on a forecast basis. These amounts reflect the addition to rate base of $8,474.1M related to the Unit 5 in-service addition as well as $1,213.9M related to the Deep Water Intake in 2031, and $159.3M in 2026 and $20.6M in 2027 for Early In-Service Facilities and Infrastructure Projects. If actual additions to rate base or their timing are different from forecast amounts and their timing, the revenue requirement impact of the difference will be recorded in the Capacity Refurbishment Variance Account and any amounts greater than the forecast amounts added to rate base will be subject to a prudence review in a future proceeding;

    ii. OM&A expenditures of $100.3M in 2027, $94.1M in 2028, $84.9M in 2029, $52.7M in 2030, and $46.5M in 2031.

    iii. PRP CCR interest amounts on a forecast basis of $297.6M in 2027, $479.9M in 2028, $667.7M in 2029, $832.0M in 2030, and $646.2M in 2031, as described in Ex. I1-1-3 and calculated in Ex. I1-1-1, Table 7.[2]

Interim Payment Amounts

29. An order declaring OPG's current payment amounts for the prescribed hydroelectric and nuclear generating facilities interim as of January 1, 2027, if the order or orders approving the payment amounts are not implemented by January 1, 2027.

[2] These amounts are included in the revenue requirement sought for approval in paragraph 2, above.

DNNP LP

30. An order declaring, for purposes of section 78.1 of the Act, that DNNP LP has satisfied the conditions set out under section 8 of O. Reg 53/05.[3]

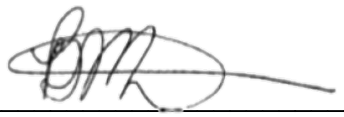
[3] Upon completion of the requirements in s. 8 of O. Reg 53/05, DNNP LP intends to file, as a preliminary matter in the proceeding, a written request for the OEB to issue an order for purposes of section 78.1 of the Act in which the OEB specifies that it is satisfied that the conditions under s. 8 have been met.

CERTIFICATION OF EVIDENCE

1.0 CERTIFICATION OF EVIDENCE AND PERSONAL INFORMATION

As Chief Commercial Officer of Ontario Power Generation Inc., I certify that, to the best of my knowledge, the evidence filed in this Application is accurate, consistent and complete in all material respects. I also certify that, to the best of my knowledge, the evidence filed in this Application does not include any personal information, as defined in the *Freedom of Information Act and Protection of Privacy Act*, that is not otherwise redacted in accordance with Rule 9A of the OEB's Rules of Practice and Procedure.

Dated at Toronto, Ontario, this 19th day of January, 2026.



Brenda MacDonald
Chief Commercial Officer

SUMMARY OF APPLICATION

This schedule provides an overview of this Application (Section 1.0), Ontario Power Generation's ("OPG" or the "Company") regulated assets and the Darlington New Nuclear Program ("DNNP") facilities (Section 2.0), priority issues in the Application (Section 3.0) and the major approvals sought in the Application (Section 4.0).

1.0 OVERVIEW

This Application lays the foundation for Ontario's energy supply over the next 25 years and beyond. The investments set out in this Application amount to over $30 billion of capital work to build, renew, and expand electrical generation assets that are critical to meeting Ontario's energy demand, supporting the province's economic growth over the decades that follow.

Ontario's Integrated Energy Plan ("IEP") is clear: the province's economy and its population are growing, and the use of electricity is increasing.[1] The Province of Ontario expects that Ontario's population will increase by over 30% by 2051, and that substantial investment in the province's industrial sector will continue. At the same time, Ontarians and businesses are relying more and more on electricity for transportation, heating, and to enable industrial processes and other drivers of economic growth.[2] The significant investments in nuclear and regulated hydroelectric facilities set out in this Application are foundational to meeting Ontario's energy needs in a manner that is affordable, secure, reliable, and clean.

The scale of the investments planned for the 2027-2031 period (the "IR term") is immense. Each of the major capital projects planned for the IR term are among the largest capital projects in Canada:

- The Pickering Refurbishment Program ("PRP") is estimated to cost $26.8 billion, with forecast in-service additions of $9.9 billion in this Application.[3]

[1] "Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7", Ministry of Energy and Mines, June 2025, p. 20.
[2] *Ibid*.
[3] Excludes interest amounts after January 1, 2026, as interest amounts will be recovered separately pursuant to Ontario Regulation 53/05. See Ex. D2-3-1 for detailed information on PRP.

- The DNNP will deliver the first grid-scale small modular reactor ("SMR") in the G7. The first of four units planned for the DNNP facilities is expected to enter commercial operation in October 2030, with forecast in-service additions of $6.6 billion.[4]
- Replacing turbine rotors at Darlington generating station, with forecast in-service additions in the IR term of $1.7B.[5] The need for this project arose from detailed inspections conducted during the Darlington Refurbishment Program ("DRP") of components not typically accessible during regular planned outages and that could not be completed within the planned DRP refurbishment window.
- Over the IR term, OPG plans to invest approximately $4.8 billion in sustaining the regulated hydroelectric assets, including $2.2 billion in turbine-generator refurbishment projects. Through these investments, OPG expects to sustain approximately 1,500 MW of existing regulated hydroelectric fleet capacity and add an estimated incremental capacity of approximately 50 MW. This includes turbine-generator refurbishments at OPG's three largest hydroelectric generating stations (Sir Adam Beck 1 GS, Sir Adam Beck 2 GS, and R.H. Saunders GS).[6]

OPG's demonstrated expertise at managing large complex refurbishment projects makes the Company uniquely qualified to simultaneously execute this suite of mega-projects. In the course of delivering the Darlington Refurbishment Program ("DRP"), OPG has developed processes and skilled resources that enable it to effectively plan and deliver the work program for the IR term. The Company has applied lessons learned on the successful execution of the DRP to these new mega-projects, helping mitigate risks and enhance project execution. As an indicator of this success, OPG is currently forecasting to deliver the DRP under-budget.[7]

At the same time, delivering the capital work program over the IR term will be a significant undertaking. Delivering multiple projects of this scale requires thorough project planning, a comprehensive resourcing strategy, and financial tools to deliver the work cost-effectively. To that end, OPG has developed a plan and ensured that necessary resources are available to

[4] Excludes interest amounts after January 1, 2026, as interest amounts will be recovered separately pursuant to Ontario Regulation 53/05. See Ex. D2-4-1 for detailed information on DNNP.
[5] Ex. D2-1-3, p. 15.
[6] Ex. F1-1-1.
[7] See Ex. D2-2-1 for detailed information on the DRP.

deliver these projects on-time, on-budget, safely, and with quality. As detailed below in Section 3.0 of this schedule, this Application and OPG's 2025-2031 Business Plan (the "Plan")[8] reflect the extensive preparation undertaken for the major investments over the IR term. The Application includes detailed evidence on planning for each of the PRP, DNNP, and the range of sustaining capital investments in OPG's nuclear and regulated hydroelectric fleets. OPG has developed a detailed resourcing strategy, redeploying resources within the Nuclear business over the IR term, allowing it to make the best use of existing skilled staff to support PRP and to enable a smooth and cost-effective transition back to operations once Pickering returns to commercial operations. Despite the significant demands on OPG resources over the IR term, the Company's workforce is expected to remain stable over the period.

The Application will also deliver value for ratepayers. It includes rate-setting mechanisms that will adequately fund the investments planned for the IR term, while incorporating stretch reductions reflecting appropriate expectations of continuous improvement over the IR term. Rate-setting and financial mechanisms supporting the Application include:

- A concurrent cost recovery ("CCR") mechanism established under Ontario Regulation 53/05 ("O. Reg. 53/05") that would help provide the cash flow necessary to fund the PRP and DNNP, while also lowering borrowing requirements and associated costs for these projects, to the long-term benefit of the ratepayer. Details on the CCR mechanism are set out in Ex. I1-1-3.
- The Application proposes forms of custom incentive rate-setting ("Custom IR") that build on the rate-setting frameworks previously approved by the OEB, adjusted to reflect the amount of planned capital investments in both the hydroelectric and nuclear fleets. Details on the propose Custom IR frameworks are provided in Ex. A1-3-2.
- The Application also proposes a payment amount-shaping proposal to mitigate customer bill impacts in the first year of the IR term. Reflecting customer engagement research conducted by Innovative Research Group, an independent public opinion research expert, OPG proposes to defer recovery of $500 million of nuclear revenue requirement by one year, from 2027 to 2028. This approach will reduce bill impacts on a typical residential

[8] A detailed overview and copy of the Plan are provided at Ex. A2-2-1.

customer's 2027 monthly bill by approximately $2.50. Details on the rate-shaping proposal are set out in Ex. I1-3-2.

Consistent with the Province of Ontario's expectations, during the IR term, OPG plans to continue planning and preparation activities for potential new hydroelectric and nuclear generation on OPG's sites. The proposed revenue requirements in the Application do not include non-capital or capital costs related to potential new generation facilities other than the DNNP. Any such costs with respect to nuclear development opportunities incurred by OPG during the IR term would be recorded in the Nuclear Development Variance Account.

Furthermore, the federal government has proposed a 15% refundable tax credit for certain clean electricity investments ("CEITC") that could be available to OPG and would reduce borrowing requirements. At the time of filing the Application, no legislation implementing this credit is in place and the CEITCs are not reflected in OPG's 2025-2031 Business Plan. OPG will account for such credits as a reduction in the capital costs of the underlying projects. The Application proposes to return to customers the revenue requirement of the CEITCs, once available, through a series of variance accounts. The CEITCs are discussed further in Ex. F4-2-1, Section 3.6.1.

1.1 A Made-in-Ontario Plan

OPG's operations are supported by a robust, Ontario-based supply chain that has been developed and refined over decades. This network provides the specialized expertise required to maintain and operate nuclear and hydroelectric facilities safely and reliably, while ensuring continuity of supply and mitigating risk in an increasingly complex global environment.

The strength of OPG's supply chain is fundamental to meeting Ontario's long-term electricity needs. By maintaining a localized procurement focus, OPG reduces exposure to international supply disruptions and ensures timely access to critical components, services, and skilled labor. This approach safeguards the reliability of Ontario's electricity system and supports the production of power to Ontarians, consistent with the procurement process measures outlined in Ex. F3-3-1.

OPG's supply chain also provides significant economic benefits to Ontario. Each year, OPG invests approximately $4.5 billion in procurement, with the majority directed to Ontario-based suppliers. More than 10,000 suppliers across the province contribute to nuclear and hydroelectric projects, sustaining thousands of skilled jobs and generating substantial economic activity. For example, the DRP – a $12.8 billion investment – will extend the life of four nuclear units to 2055, securing 20 percent of Ontario's electricity supply and contributing an estimated $75 billion to Ontario's GDP over the life of the station, while supporting an average of 14,200 jobs annually.

The investments planned for the IR term continue the trend set by the DRP, contributing both to Ontario's electrical needs and energy security, but also the province's economic strength. The PRP will create and sustain thousands of high-quality jobs and strengthen the province's nuclear supply chain. The Conference Board of Canada projects the full refurbishment will create 11,000 jobs per year and contribute $19.4 billion to Ontario's GDP over 11 years, with approximately 90% of spending occurring in Ontario. The DNNP will similarly contribute to the province's economic strength, with operation and maintenance of the four units will add $38.5 billion to Canada's GDP over the next 65 years, with 80% of project spending going to Ontario companies. Construction and operations will sustain, on average, an estimated 3,700 highly skilled jobs for the next 65 years. In keeping with OPG's Reconciliation Action Plan, OPG has committed to significant procurement with Indigenous businesses within the supply chain.

Similarly, OPG's hydroelectric capital program will redevelop and refurbish stations across Ontario, securing up to 830 MW of clean generation capacity and creating more than 1,000 skilled jobs.

These initiatives demonstrate OPG's ability to leverage its supply chain to deliver projects on time and on budget, while driving economic growth and supporting the province's electricity needs. OPG's contribution to Ontario's supply chain ecosystem helps ensure the province remains a leader in clean energy generation, while supporting long term economic growth.

1.2 The Applicants

This Application is filed jointly by OPG and DNNP LP. DNNP LP is a limited partnership formed under the laws of the Province of Ontario, and DNNP GP Inc. ("DNNP GP") is the managing general partner of DNNP LP with the authority to act on behalf of DNNP LP. DNNP LP will be a newly prescribed generator subject to certain conditions set out in section 8 of O. Reg. 53/05 and is entering into a lease for the DNNP facilities with OPG. DNNP LP will undertake the development, construction, and operation of the DNNP facilities, with OPG contracted to act as the project manager and operator of the facilities. The Application assumes that DNNP LP enters into the lease and associated agreements and that the DNNP asset transfer from OPG all occur at the end of 2025. DNNP LP will not have its own workforce and will contract for all applicable services with OPG, and will therefore reimburse OPG for its fully allocated costs of providing the services. An overview of DNNP LP is provided in Ex. A1-4-4. In this Application, "DNNP facilities" denotes the elements associated with DNNP LP's requests in the Application such as the components of its revenue requirement and its production forecast.

An overview of the DNNP, including the roles of the relevant stakeholders, is provided at Ex. D2-4-1. The approvals sought with respect to each applicant are set out in Ex. A1-2-2.

2.0 REGULATED ASSETS

The basis for the application can be found in O. Reg. 53/05 and section 78.1 of the *Ontario Energy Board Act, 1998* (the "Act").

OPG's prescribed generating facilities consist of both hydroelectric generating stations and nuclear generating stations (the "prescribed facilities" or the "regulated facilities"), all of which participate in the electricity market administered by the Independent Electricity System Operator ("IESO") in accordance with the Ontario Market Rules. The regulated facilities consist of two nuclear generating stations with a capacity of 3,094 MW at the Pickering Nuclear Generating Station ("Pickering")[9] and 3,512 MW at the Darlington Nuclear Generating Station

[9] Combined capacity of Pickering Units 1, 4, and 5-8.

("DNGS"), and 54 hydroelectric generating stations (the "regulated hydroelectric facilities") with a total capacity of 6,566 MW for a combined regulated generating capacity of 13,172 MW.

DNNP LP's prescribed generating facilities during the IR term will consist of the first of four units at the DNNP site. Once complete, the DNNP is expected to have a total capacity of approximately 1,200 MW across the four units.

The budgeting and business planning process that underlies this Application is described in Ex. A2-2-1 (Corporate), Ex. F1-1-1 (Hydroelectric), and Ex. F2-1-1 (Nuclear).

3.0 PRIORITY ISSUES

In its Decision and Order in EB-2010-0008, the OEB encouraged the participating parties to focus their attention in future applications on the highest priority issues. Accordingly, this Application has been crafted in such a way as to highlight its highest priority issues. This section summarizes those issues.

3.1 Pickering Refurbishment Program

The PRP is a multi-year, multi-phase program at Pickering to enable the replacement or rehabilitation of life-limiting critical components and the completion of upgrades to meet regulatory requirements within Units 5-8. The PRP, when completed, will allow Units 5-8 to continue safe and reliable operation for an additional 38 years.

Pickering Units 1-4 have ceased commercial operation. Without refurbishment, Pickering Units 5-8 would also cease production in 2026.

OPG is conducting its planning for PRP over approximately five years, relative to ten years for the Darlington Refurbishment Program ("DRP"). This comparatively shorter timeframe is enabled by OPG's ability to leverage the successful planning and execution of DRP, including the processes already in place, supply chain infrastructure that was built for DRP, DRP's commercial structure as applicable to PRP, as well as significant operational experience and

lessons learned. This has created efficiencies for PRP, allowing it to complete the necessary diligence, detailed planning and cost and schedule estimation in the shorter timeframe.

The PRP also thoroughly reflects inherent differences between the two refurbishment programs. In many ways, the PRP is a much more complex undertaking than the DRP given the older age of the station and its technology, and the resulting need for much more significant replacements. In particular, OPG is removing all 12 boilers in each of Units 5-8 and replacing them with new boilers, whereas the DRP only conducted inspections and water lancing of the boilers. This is a significant and complex undertaking that includes needing to cut two holes at the top of the roof of the reactor containment dome to create access points to extract the existing boilers out of the station. In addition, OPG is also constructing a Deep Water Intake to draw water from deep below the surface of Lake Ontario to ensure a stable supply of clean, cooler water to the forebay. This work involves the tunnelling and construction of an offshore intake tunnel, cofferdam and offshore intake shaft and is expected to improve thermal efficiency, support increased electrical power output, reduce biofouling events, decrease fish impingement and entrainment, and enhance resilience to climate change.

Another key difference between the PRP and the DRP is that OPG will be executing all four units in parallel, which creates both resourcing and execution challenges, and a unique opportunity to leverage Pickering's existing operational staff. The PRP is leveraging a workforce strategy that blends OPG's existing workforce with contractor staff where appropriate. This strategy seeks to redeploy existing OPG operational staff with critical expertise and knowledge of the station to certain PRP work, such as radiation protection, maintenance and fuel handling. That strategy ensures timely access to sufficient and proficient labour to meet project schedules, fulfilling resource demands particularly during overlapping units, leverages skilled employees familiar with the station for safe and efficient execution, and mitigates the risk of potential labour shortages in the market. To enable the full extent of this workforce strategy, OPG successfully negotiated the necessary redeployment agreements with the PWU and Society and optimized jurisdictional terms for the PWU, with the Building Trades Unions. Further details on these labour arrangements are discussed in Ex. F4-3-1,

Sections 2 and 5. Further description of this workforce strategy is provided in Ex. D2-3-4, Section 2.3.

The PRP is currently in the Definition Phase, which has advanced scope and design maturity. The completion of detailed engineering deliverables as well as risk analysis and contractor input have provided increased certainty on technical requirements and material quantities, all of which were used to finalize contracting and procurement strategies and secure and award all of the major PRP contracts.

As a result of this detailed planning conducted to date, on November 14, 2025, OPG's Board of Directors approved the PRP Release Quality Estimate ("RQE"). The RQE to refurbish all four Units 5-8 at Pickering is $26.8B including interest, escalation and contingency. In approving the RQE, the OPG Board of Directors approved the full release of PRP to complete definition deliverables prior to moving into execution for all units. Risk identification and contingency modelling has also confirmed adequate contingency for the overall program. Also embedded within the RQE is OPG's workforce strategy as described above, which provides significant cost and schedule benefits and efficiencies.

On November 26, 2025, the Province of Ontario announced that it had approved OPG's plan to refurbish Units 5-8 at Pickering, which will support the government's plan to protect Ontario workers and the province's long-term energy security.

The Application includes 10 schedules setting out extensive detail on the PRP and the planning process undertaken. The project has in place the resources, organization and processes necessary to execute PRP in its entirety, safely, on time, on budget, and with the required quality level.

3.2 Darlington New Nuclear Program

The DNNP is an SMR project at the eastern portion of OPG's Darlington New Nuclear site. This first-of-a-kind program includes the design, licensing, site preparation, construction, and commissioning of four SMR facilities (referred to as units) using the BWRX-300 reactor

technology. During the 2027-2031 IR term, the first of the four SMR units is scheduled to enter commercial operation. The construction of this first unit is currently in progress. Planning and preparations are ongoing for the remaining three units, with future construction subject to requisite approvals.

The DNNP will help Ontario meet its demand for reliable, cost effective and clean energy. The Province of Ontario has noted that:

> With electricity demand in Ontario set to soar by at least 75 per cent by 2050, the Ontario government has approved Ontario Power Generation's (OPG) plan to begin construction on the first of four small modular reactors (SMRs) at the Darlington nuclear site. Once complete, this SMR will be the first of its kind in the G7, producing enough reliable, affordable and clean electricity to power the equivalent of 300,000 homes, supporting thousands of good-paying jobs across the province and helping secure Ontario's energy supply for decades to come.[10]

On September 11, 2025, Prime Minister Mark Carney announced that the DNNP was under consideration as one of the nation-building projects that the Federal Government will support through the newly established Major Projects Office. The Federal Government's announcement noted that:

> This project will make Canada the first G7 country to have an operational small modular reactor (SMR), accelerating the commercialization of a key technology that could support Canadian and global clean energy needs while driving $500 million annually into Ontario's nuclear supply chain. Once complete, Darlington's first of four planned SMR units will provide reliable, affordable, clean power to 300,000 homes, while sustaining 3,700 jobs annually, including 18,000 during construction, over the next 65 years.[11]

[10] Province of Ontario, News Release: Ontario Leads the G7 by Building First Small Modular Reactor, May 8, 2025 <https://news.ontario.ca/en/release/1005889/ontario-leads-the-g7-by-building-first-small-modular-reactor>.

[11] Prime Minister of Canada, Prime Minister Carney announces first projects to be reviewed by the new Major Projects Office, September 11, 2025 <https://www.pm.gc.ca/en/news/news-releases/2025/09/11/prime-minister-carney-announces-first-projects-be-reviewed-new>.

In 2018, OPG began the initial planning and preparation phase for a SMR facility at the Darlington New Nuclear site. The early planning work focused on a review of available technologies and in 2021, OPG selected GE-Hitachi's BWRX-300 Boiling Water Reactor as the best technology for the DNNP. The BWRX-300 SMR is a 300 MW water-cooled, natural circulation design with passive safety systems. It leverages the existing Economic Simplified Boiling Water Reactor design certification, utilizing licensed and proven nuclear fuel, incorporating proven components and supply chains. Once operational, the staffing for the station will be based on a minimum complement strategy, leveraging the BWRX-300 plant design to optimize the workforce required to operate and maintain the plant.

The DNNP is a large, complex, first-of-a-kind, new build project. To manage the work, OPG developed an overall commercial strategy as well as contracting strategies for specific scopes of work. The primary commercial strategy selected by OPG to deliver Unit 1 and the common scope facilities is an Integrated Project Delivery ("IPD") model in which the key parties involved in the design, fabrication and construction of a project are joined together under a single agreement. The IPD model is a delivery method that enhances project collaboration and integration between the parties, and employs risk sharing rather than risk transfer. It also establishes incentives to promote the best outcomes for the project, with a focus on cost management, schedule adherence and generation performance. Under this model, OPG engaged four non-owner parties, and together the parties worked towards establishing the project scope and design, schedule, cost, and quality, ultimately improving the definition and maturity of the project.

On March 6, 2025, after the extensive, detailed planning completed in the Definition Phase (also referred to as the Validation Phase), OPG's Board of Directors approved the $7.7B Release Quality Estimate ("RQE") for Unit 1 and Common Scope Facilities, transitioning Unit 1 into the Execution Phase. On May 8, 2025, the Ontario Government announced its approval of OPG's plan to proceed with construction on the first of four SMRs at the DNNP site.[12]

[12] Province of Ontario, News Release: Ontario Leads the G7 by Building First Small Modular Reactor, May 8. 2025 <https://news.ontario.ca/en/release/1005889/ontario-leads-the-g7-by-building-first-small-modular-reactor>.

The Application includes 10 schedules setting out extensive detail on the DNNP Unit 1 and Common Scope Facilities and the planning process undertaken. The project has in place the resources, organization and processes necessary to execute safely, on time, on budget, and with the required quality level.

3.3 Hydroelectric and Nuclear Sustaining Investment

OPG must continue investing to sustain the regulated hydroelectric and nuclear generating facilities over the IR term, maintaining the stations' capacity to operate safely and reliably.

3.3.1 Hydroelectric Sustaining Investments

OPG's regulated hydroelectric generating facilities are a central pillar of Ontario's renewable, low-cost, practically zero-emissions electricity supply. Over the IR term, OPG's hydroelectric sustaining program consists of concrete structure and dam rehabilitation works to address degradation related to age and environmental factors, dam safety, water control, civil rehabilitation, station service and transformer upgrade projects, and work to ensure ongoing equipment reliability.

With the age of OPG's regulated hydroelectric assets averaging 90 years, many degraded components are at or approaching end-of-life and require significant investment during the forecast period to ensure that the assets can continue to help meet the province's energy needs for decades to come. The Plan reflects these important investments, which accounts for $2,193.6M of capital expenditures on refurbishment projects in the 2027-2031 forecast period, and $39.7M in Project OM&A expenditure for overhaul projects in the 2027 test year.

Over the IR term, OPG expects to make capital investments to sustain approximately 1,500 MW of the existing regulated hydroelectric fleet capacity and add an estimated incremental capacity of approximately 50 MW. This includes turbine-generator refurbishments at OPG's three largest hydroelectric generating stations (Sir Adam Beck 1 GS, Sir Adam Beck 2 GS,[13] and R.H.

[13] Province of Ontario, News Release: *Ontario Refurbishing Hydroelectric Stations in Niagara*, April 16, 2024.

Saunders GS),[14] supported by recent announcements from the Province of Ontario and reaffirmed in the IEP.[15]

OPG plans to invest approximately $318.4M capital in the 2027-2031 forecast period and $25.3M Project OM&A in the 2027 test year to address concrete deterioration through rehabilitation and restoration projects. Over time, civil structures deteriorate due to various environmental factors such as thermal expansion-contraction, water seepage, freeze-thaw damage, corrosion of reinforcements, and abrasion. An additional cause of deterioration is the unexpected expansion of concrete due to long-term chemical reactions, specifically Alkali Aggregate Reaction. Examples of such capital projects include Otto Holden GS Refurbish Stop Log Sluice Piers and Aguasabon Dam Rehabilitation. Further details on concrete rehabilitation capital projects are provided in Ex. D1-1-2.

Details on OPG's planned investments at the regulated hydroelectric facilities are set out in Ex. D1-1-1.

3.3.2 Nuclear Sustaining Investments

In addition to the nuclear mega-projects planned for the IR term, OPG must continue to invest to sustain the existing facilities, including Pickering infrastructure that can be efficiently executed while the station is being refurbished.

The Pickering capital program represents a change from recent years, when very limited sustaining work was conducted at the station due to the assumed upcoming end of commercial operation. Over the business plan period, a larger Pickering program is planned to focus on sustaining work that is more efficiently executed during the multi-unit refurbishment window, supports improved post refurbishment unit reliability, and renews necessary station infrastructure. These projects are planned to be managed separately from the PRP, which will be focused primarily on the rehabilitation or replacement of critical life-limiting components and the completion of upgrades to meet regulatory requirements. This approach is consistent with

[14] Province of Ontario, News Release: *Ontario Refurbishing Hydroelectric Station in Cornwall*, May 10, 2024.
[15] IEP, p. 9, 40, 54.

the Darlington Refurbishment – it positions the units for strong performance while balancing the need for more extended planned outages in the future with managing the complexity of the refurbishment scope. OPG will continue to develop and prioritize the Pickering sustaining portfolio to ensure it optimally supports post-refurbishment operations and successful execution of the PRP.

The Darlington capital program will continue to focus on ensuring that the refurbished station is well positioned for sustained strong reliability performance over the long term.

Capital expenditures on the nuclear project portfolio over the IR term are generally stable and averaging approximately $500M annually, with the Darlington portion declining to $204.4M by the end of the IR term, whereas, the annual Pickering portfolio expenditures are planned to increase to $261.1M by the end of the IR term. In addition, there is an increase to the non-portfolio project listing during the IR term for major equipment replacements or rehabilitation or otherwise necessary investments to address risks to achieving Darlington's post-refurbishment operations.

Details on OPG's planned capital expenditures at the nuclear facilities are set out in Ex. D2-1-2.

3.4 Project Excellence

Supporting the forecast capital investments and the mega-projects listed above, OPG has continued to develop and refine its strong project management processes. In particular, OPG has expanded the project management approach historically used in the nuclear business across the enterprise, establishing an Enterprise Project Management Office to standardize this approach across the Company.

OPG employs an enterprise-wide portfolio management approach to assess, prioritize, and deliver all portfolio projects, both capital and OM&A. The portfolio management approach is characterized by two interrelated cycles of Asset Investment Planning and Management (i.e., defining the portfolio) and Portfolio Management and Execution (i.e., delivering the portfolio).

Over the historical period, OPG has further enhanced its project management proficiency programs and established a Construction Centre of Excellence while continuing to seek opportunities to improve and standardize its portfolio management approach.

Details on OPG's expanded, enterprise-wide portfolio management process are provided in Ex. D2-1-1. OPG also provides detailed information on the project management approaches in the PRP and DNNP mega-projects as noted in Sections 3.1 and 3.2 above.

3.5 Workforce and Resource Strategy

In addition to the workforce strategy described above for PRP, OPG must ensure that it has the appropriate resources available to execute the substantial work program planned for the IR term. OPG's regular headcount is forecast to increase by approximately 30% from 2021-2027, then remain stable through the IR term. This is in contrast to the context of EB-2020-0290, at which time OPG was preparing to downsize as a result of then-planned end of commercial operations at Pickering in 2025.

With growing external labour market pressures and a shrinking pool of skilled workers, competition for talent, especially for energy project professionals, has intensified. This is compounded by the demand for major infrastructure projects and the need for project execution excellence, making it increasingly challenging for OPG to secure and retain the skilled workforce needed over the IR term and beyond. To meet the workforce demand during the IR term, OPG has executed various strategies to ensure the Company has the resources required through collective bargaining measures that enable greater resourcing flexibility, proactive workforce planning and strategic hiring.

OPG is focused on ensuring that the Company's employees have the right skills in place to meet future workforce needs. This is done by identifying the necessary skills for OPG's future workforce, strengthening and expanding the skilled trade talent pipeline, expanding early career and career progression opportunities, and strengthening partnerships with educational institutions and programs in the utility and energy industry. Key workforce planning strategies that OPG has undertaken include:

- Enterprise staffing aimed at ensuring that staffing levels and decisions support ongoing operational and project needs, while optimizing the workforce and managing risks for high-demand skills and roles in the market.
- Transition plans to efficiently and effectively manage staff deployment during the completion of the DRP and Pickering Units 5-8 operations in 2026, and the subsequent refurbishment of Pickering.
- Regulated hydroelectric operations have targeted training initiatives for developing proficiency in the workforce. These training and development activities will be a key to success as Renewable Generation brings on additional staff to support the increased work program described in Ex. F1-1-1, primarily the regulated hydroelectric refurbishment projects.
- Re-introduction of early career programs to better attract talent and promote continuity in talent pipelines for ongoing operations and key project.
- Succession planning to ensure leadership development enables a diverse and robust talent pipeline.
- Expanded outreach programs to academic institutions and career fairs to support increased supply in the market for skilled trades and STEM roles.
- Support for various skilled trades initiatives to increase a diverse supply, the creation of an industry-wide resource demand profile, and other efforts to balance supply and demand.

OPG's workforce strategy is detailed in Ex. F4-3-1, Section 5.

3.6 Custom Rate-setting Frameworks

The Application proposes two distinct Custom Incentive Rate-setting ("Custom IR") frameworks for the regulated hydroelectric facilities and the nuclear facilities and the DNNP. These Custom IR frameworks reflect the business context of the facilities and the major capital investments that are being made over the IR term.

For the regulated hydroelectric facilities, the Application proposes a Custom IR framework that continues to set payment amounts based on a price-cap index, consistent with the approach applied for the 2017-2021 period in EB-2016-0152, but with the addition of a custom capital

factor ("C-factor") and an adjustment to hold the gross revenue charge ("GRC") embedded in payment amounts constant over the IR term. The C-factor is intended to address the substantial incremental capital investments required over the forecast period which would not be funded under the price-cap framework. This approach preserves the efficiency incentives inherent in a price-cap model for "steady state" operations, while ensuring adequate funding for capital projects necessary to address the conditions of the aging assets at the regulated hydroelectric facilities. The proposed inflation factor, productivity factor, and stretch factor are calculated based on independent expert analyses conducted by London Economics International LLC, including econometric total cost benchmarking of the regulated hydroelectric facilities.

For the nuclear facilities, the Application proposes that payment amounts continue to be established using the Custom IR framework approved by the OEB in the EB-2020-0290 proceeding, which includes individual revenue requirements for each of the five years of the 2027-2031 rate term, with some adjustments for the DNNP facilities to reflect the business context of DNNP LP. This approach reflects the unique circumstances of the nuclear operations, including the scale and complexity of major capital initiatives such as the PRP and the DNNP. The Application proposes that cost benchmarking of OPG's nuclear facilities will continue to be used to determine the nuclear stretch factor in respect of the Company's nuclear operations OM&A costs, allocated corporate support OM&A costs and asset service fees, as well as nuclear operations and corporate support services in-service capital additions.

The Application also proposes to continue the earnings sharing mechanism for OPG's regulated facilities introduced in the EB-2020-0290 Settlement Proposal over the IR term. OPG proposes to base the earnings sharing mechanism on its combined regulated 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 5-year period from 2027-2031.

3.7 Deferral and Variance Accounts

The Application proposes to clear the audited balances in all of OPG's deferral and variance accounts as at December 31, 2024, less amortization amounts previously approved by the OEB in EB-2023-0336 and EB-2020-0290 for the 2025-2026 period, except for the hydroelectric components of the Capacity Refurbishment Variance Account, the components of the Nuclear Development Variance Account not related to DNNP, and the Pickering B Variance Account. The basis of this proposal is set out in Ex. H1-1-1.

Adjusted for OEB-approved 2025-2026 amortization amounts, the proposed year-end 2024 account balances for disposition in this application are a net credit balance of $102.4M[16] for OPG's regulated hydroelectric facilities and a net debit balance of $878.8M[17] for OPG's regulated nuclear facilities.[18]

The Application proposes to continue all existing deferral and variance accounts, except for three accounts which are no longer required and which OPG accordingly proposes to terminate. The Application also proposes to expand the scope of OPG's Gross Revenue Charge Variance Account to apply to all of OPG's regulated hydroelectric facilities, along with capturing the revenue requirement impact of any legislated or regulatory changes to the GRC construct, and to align the methodology for the CRVA as it applies to the regulated hydroelectric facilities with the proposed rate-setting framework. The Application also proposes to extend the SR&ED ITC Variance Account (OPG) to include OPG's regulated hydroelectric facilities.

The Application proposes to establish five new deferral and variance accounts for OPG:

- Global Hydroelectric Capital Variance Account
- Clean Electricity ITC Variance Account (OPG)
- DNNP Nuclear Liability Deferral Account

[16] Ex. H1-2-1, Table 1, col. (f) line 16.
[17] Ex. H1-2-1, Table 2, col. (f) line 30.
[18] A debit entry or balance is an amount to be collected from ratepayers. A credit entry or balance is an amount to be returned to ratepayers.

- Payment Amount Shaping Deferral Account
    - Change of Laws Deferral Account (OPG)

The Application also proposes to establish seven new deferral and variance accounts for DNNP LP:

- Income and Other Taxes Variance Account (DNNP)
- Pension and OPEB Cost Variance Account (DNNP)
- Nuclear Deferral and Variance Over/Under Recovery Variance Account (DNNP)
- SR&ED ITC Variance Account (DNNP)
- Impact for IFRS Deferral Account (DNNP)
- Clean Electricity ITC Variance Account (DNNP)
- Impact of Change in Tax Status Variance Account (DNNP)
- Change of Laws Deferral Account (DNNP)

4.0 SUMMARY OF APPROVALS

4.1 Payment Amounts

For the hydroelectric generation facilities, OPG is requesting that the OEB establish a payment amount of $51.39/MWh effective January 1, 2027, to be escalated annually by the custom price-cap index framework set out in Ex. A1-3-2.

For OPG's nuclear generation facilities and the DNNP facilities, OPG is requesting that the OEB establish blended payment amounts of:

- $206.76/MWh effective January 1, 2027;
- $192.52/MWh effective January 1, 2028;
- $203.20/MWh effective January 1, 2029;
- $199.97/MWh effective January 1, 2030; and
- $220.68/MWh effective January 1, 2031.

In addition, OPG is requesting payment riders for the regulated hydroelectric and nuclear production to amortize the audited balances of the deferral and variance accounts as of

December 31, 2024 as calculated in Ex. H1-2-1. The proposed nuclear payment rider is $7.19/MWh in 2027, $5.04/MWh in 2028, $5.36/MWh in 2029, $2.48/MWh in 2030, and $2.19/MWh in 2031. The proposed hydroelectric payment rider is $(1.17)/MWh in 2027, $(1.17)/MWh in 2028, $(1.17)/MWh in 2029, $0.00/MWh in 2030, and $0.00/MWh in 2031.

As described in Ex. I1-1-2, the forecast combined impacts of the proposed payment amounts and payment riders on the monthly bill of a typical residential customer bill are:

- An increase of $7.94 in 2027;
- An increase of $2.45 in 2028;
- An increase of $1.37 in 2029;
- An increase of $0.74 in 2030; and
- An increase of $4.67 in 2031.

4.2 Rate Base and Capital Structure

The forecast of rate base for the regulated hydroelectric facilities is $9,135.1M in 2027. The forecast of rate base for the nuclear facilities is $15,794.7M in 2027, $16,328.3M in 2028, $16,265.0M in 2029, $16,867.5M in 2030, and $23,587.9M in 2031. The forecast of rate base for the DNNP facilities is $0.0M in 2027, $0.0M in 2028, $2.1M in 2029, $1,371.1M in 2030, and $6,530.0M in 2031. Further discussion of nuclear rate base, including variance explanations, can be found in Ex. B1-1-1.

Additional details on in-service additions for the regulated hydroelectric facilities, nuclear facilities, and corporate capital projects impacting rate base are provided in Exhibits D1, D2 and D3, respectively. Additional detail on depreciation and amortization expense is provided in Ex. F4-1-1. Details on in-service additions for the DNNP facilities are provided in Exhibit D2, Tab 4, Schedule 10.

The Application incorporates a return on equity ("ROE") of 9.11% for OPG and DNNP LP based on 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. For OPG, this is applied to the regulated rate base using a capital structure of 52% common equity and 48%

debt.[19] This capital structure is supported by the findings of the Common Equity Ratio Study carried out by Concentric Energy Advisors.[20] The proposed capital structure for OPG reflects the heightened risks the company will experience primarily related to the execution of major projects such as the PRP, 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%.

For DNNP LP, as informed by Section 13.(1) of O. Reg. 53/05 which establishes the DNNP Generator Capital Structure Variance Account 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 being prudently incurred, the Application has applied a 100% equity funded capital structure. This is supported by the expert testimony of Mr. Cliff Inskip.[21] Further information on the proposed capital structures of OPG and DNNP LP are provided in Ex. C1-1-1.

4.3 Revenue Requirement

OPG's 2027 regulated hydroelectric revenue requirement is $1,668.3M, excluding amortization of any deferral and variance accounts. The derivation of regulated hydroelectric revenue requirement is set out in Ex. I1-1-1, Table 1.

OPG's nuclear revenue requirement, net of the proposed stretch factor is $4,062.8M for 2027, $4,257.3M for 2028, $4,676.5M for 2029, $4,881.7M for 2030, and $5,736.9M for 2031,

19 OPG proposes to establish the ROE for the IR term using the prevailing ROE specified by the OEB as of the effective date of the Payment Amounts Order.
20 Ex. C1-1-1, Attachment 1.
21 Ex. C1-1-1, Attachment 3

excluding amortization of any deferral and variance accounts. The derivation of nuclear revenue requirement is set out in Ex. I1-1-1, Table 2.

DNNP revenue requirement is $302.0M for 2027, $381.4M for 2028, $417.0M for 2029, $582.1M for 2030, and $1,076.1M for 2031. The derivation of DNNP revenue requirement is set out in Ex. I1-1-1, Table 2a.

RATE-SETTING FRAMEWORK AND PERFORMANCE REPORTING

1.0 OVERVIEW

The Application proposes that payment amounts for the prescribed hydroelectric and prescribed nuclear facilities for the period from January 1, 2027-December 31, 2031 (the "IR term") be set based on Custom Incentive Rate-setting ("Custom IR") frameworks consistent with those approved by the OEB in EB-2016-0152[1] and EB-2020-0290,[2] as adjusted to reflect the increased capital investments that OPG is making for the prescribed hydroelectric facilities in the current IR term, and, for the Darlington New Nuclear Program ("DNNP") facilities, to reflect the business context of the program and DNNP LP.[3]

This exhibit provides detailed information on the Custom IR proposals as follows:

- Section 2.0: Prescribed Hydroelectric Facilities Rate Setting Proposal
- Section 3.0: Prescribed Nuclear Facilities Rate Setting Proposal
- Section 4.0: Other Elements of Custom IR Proposals
- Section 5.0: Performance Scorecard

The Application proposes to set payment amounts for the prescribed hydroelectric facilities using a price-cap index Custom IR framework, consistent with the approach applied for the 2017-2021 period in EB-2016-0152, but with the addition of a custom capital factor ("C-factor") and an adjustment factor to hold gross revenues charges ("GRC") and other water agreement costs embedded in payment amounts constant over the IR term ("GRCF").[4] The C-factor is intended to address the substantial incremental capital investments required over the forecast period which would not be funded under the price-cap framework. This approach preserves the efficiency incentives inherent in a price-cap model for "steady state" operations, while ensuring

[1] Decision and Order, EB-2016-0152, December 28, 2017, pp. 135-136.
[2] Decision and Order, EB-2020-0290, November 15, 2021, p. 32.
[3] The OEB did not approve a rate-setting framework for the prescribed hydroelectric facilities in the EB-2020-0290 proceeding, as the payment amounts for those facilities were legislatively frozen under O. Reg. 53/05, s. 6(2)13.
[4] Gross revenue charges and other water agreement costs are presented in aggregate in the Application and are described in Ex. F1-4-1. As the GRC represents the large majority of these costs, the proposed treatment of the GRC is also applied to the other water agreement costs, for simplicity.

adequate funding for capital projects necessary to address the conditions of the aging assets at the prescribed hydroelectric facilities. The GRCF is designed to hold the GRC expense embedded in payment amounts constant over the IR term due to the non-escalating nature of this legislatively prescribed cost. The calculation of the proposed rate-setting methodology is described in Sections 2.0 and 4.0 below.

The Application proposes that payment amounts for the prescribed nuclear facilities continue to be established using the Custom IR framework approved by the OEB in the EB-2016-0152 and EB-2020-0290 proceedings, which includes individual revenue requirements for each of the five years of the 2027-2031 rate term, with some adjustments for the DNNP facilities to reflect the business context of DNNP LP. This approach reflects the unique circumstances of the nuclear operations, including the scale and complexity of major capital initiatives such as the Pickering Refurbishment Program ("PRP") and the DNNP, which cannot be accommodated within a standard price-cap framework. Under the proposed framework, cost benchmarking will continue to be used to determine a nuclear stretch factor for OPG's regulated nuclear facilities, promoting continuous improvement. Further details on the proposed nuclear rate-setting methodology are provided in Sections 3.0 and 4.0 below.

The Application's proposal is informed by the OEB's Decision and Order in EB-2016-0152, the principles set out in the *Renewed Regulatory Framework* ("RRF"),[5] the OEB's Report on *Incentive Rate-making for Ontario Power Generation's Prescribed Assets* ("IR Report"),[6] and the *Handbook for Utility Rate Applications* ("Handbook").[7]

This evidence also sets out the proposal for annual performance reporting for both the prescribed hydroelectric facilities and the prescribed nuclear facilities. As directed by the EB-2016-0152 Decision and Order, the Application proposes a performance reporting "scorecard"

[5] *Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012.
[6] *Report of the Board: Incentive Rate-making for Ontario Power Generation's Prescribed Generation Assets* (EB-2012-0340), March 28, 2013.
[7] *Handbook for Utility Rate Applications*, October 13, 2016. Although the Handbook is primarily directed at electricity distributors, OPG has adopted the principles set out within it where applicable to regulated electricity generation.

that summarizes performance measures, guided by the Handbook.[8] The proposed scorecard and rationale are provided in Section 5.0 below.

2.0 PRESCRIBED HYDROELECTRIC FACILITIES RATE-SETTING PROPOSAL

2.1 Overview of Hydroelectric Custom Price-cap Index Proposal

The Application proposes to continue setting hydroelectric payment amounts for the 2027-2031 period using a price-cap index framework, as was used to set OPG's hydroelectric payment amounts during the 2017-2021 period,[9] with the addition of a C-factor and GRCF. This form of hydroelectric Custom IR is based on the Fourth Generation IR ("4GIRM") price-cap index methodology in the RRF.

The Application proposes to determine the 2027 hydroelectric payment amount using a forward test year cost of service approach, and to establish an annual price cap adjustment for 2028-2031 using proposed I- and X-factors.[10] In addition to the I- and X-factors set out in the 4GIRM price-cap methodology, the Application is proposing a C-factor to provide funds incremental to the annual price-cap adjustment in order to recover the cost of capital investments required at the prescribed hydroelectric facilities during the period, and a GRCF to hold the GRC expense embedded in payment amounts constant over the IR term to reflect its non-escalating nature by virtue of how it is determined pursuant to the *Electricity Act, 1998*.

The C-factor is designed to address the significant capital investment that could not be funded in a timely manner through a typical price cap framework. This form of Custom IR maintains an incentive for OPG to seek incremental efficiencies in the "steady state" operations of its prescribed hydroelectric facilities, while simultaneously providing sufficient funding to support the investment required to address the conditions of these aging assets in alignment with

[8] Decision and Order, EB-2016-0152, December 28, 2017, p.146.
[9] EB-2016-0152, Ex. A1-3-2.
[10] The proposed use of I- and X- factors in the annual adjustment mechanism is consistent with the framework used to set OPG's 2017-2021 hydroelectric payment amounts in EB-2016-0152. The forward test year approach was not used in the 2017-2021 framework; instead, OPG's "going-in" rates were based on the 2014/2015 cost of service payment amounts approved in EB-2013-0321. Further detail can be found at EB-2016-0152, Ex. A1-3-2.

Ontario's Integrated Energy Plan.[11] The calculation of the proposed rate-setting methodology is set out below.

The Application also proposes to establish an asymmetrical Global Hydroelectric Capital Variance Account ("GHCVA") that would address a scenario in which the actual capital-related revenue requirement determined based on OPG's actual in-service amounts for the prescribed hydroelectric facilities over the 2028-2031 period is less than the capital-related revenue requirement provided through the payment amounts inclusive of the C-factor. The proposed account is asymmetric in favour of ratepayers and would be evaluated cumulatively over the IR term.

For ease of reference, Chart 1 below compares the structure of the hydroelectric ratemaking proposal in this Application to the previous hydroelectric ratemaking method approved in EB-2016-0152.

[11] See Ex. D1-1-2 for discussion on the capital expenditures and the in-service amounts for the regulated hydroelectric facilities during the IR term.

Chart 1 – Summary of Hydroelectric Custom IR Framework and Differences from EB-2016-0152

Ratemaking Element	2017-2021 Ratemaking Method (EB-2016-0152)	2027-2031 Proposal	Summary of Differences from EB-2016-0152
Year 1 / "Going-In" Rates	Determined based on cost of service review of 2014/2015 test years (EB-2013-0321)	Standard cost of service rebasing based on 2027 test year	Cost of service rebasing information was not provided in EB-2016-0152 but is provided in this submission
Form	Price-cap Index	Custom Price-cap Index	Additional annual adjustment factors included in this submission
Coverage	Comprehensive (capital and OM&A)	Comprehensive (capital and OM&A)	No Change
Annual Adjustment Mechanism	1+(I-X)	1+(I-X+C-GRCF)	C-factor is designed to fund five-year capital related requirements GRCF is designed to hold constant the GRC expense embedded in payment amounts over the IR term
Inflation	Composite Index. Generation Industry weighted Labour Index (Ontario AWE) and Non-Labour Index (GDP-IPI-FDD)	Composite Index. Generation Industry weighted Labour Index (Ontario AWE) and Non-Labour Index (GDP-IPI-FDD)	Proposed change in weighting between Labour and Non-Labour
X-factor	X-factor comprised of: 1) Hydroelectric generation industry Total Factor Productivity "TFP" growth potential; and 2) Stretch Factor	X-factor comprised of: 1) Hydroelectric generation industry TFP growth potential; and 2) Stretch Factor	No change to X-factor design. Productivity and stretch values calibrated based on expert TFP growth and econometric cost benchmarking studies

Ratemaking Element	2017-2021 Ratemaking Method (EB-2016-0152)	2027-2031 Proposal	Summary of Differences from EB-2016-0152
Capacity Refurbishment Variance Account ("CRVA")	Reference amount based on going-in payment amount. Annual reference amount escalated by (I-X) Recovery subject to total capital in-service exceeding depreciation expense recovery available through payment amounts, on a five-year cumulative basis. Annual funding implicit in payment amounts escalated by (I-X)	Reference amounts determined for each year of the IR term based on forecast CRVA-eligible projects, to be reviewed on a five-year cumulative basis Recovery subject to total capital-related revenue requirement exceeding capital funding available through payment amounts inclusive of C-factor (see interaction with GHCVA)	Annual reference amounts for the CRVA rather than amount in going-in payment amount escalated by (I-X)
Global Hydroelectric Capital Variance Account	N/A	Records the difference, for the 2028-2031 period and asymmetrically in favour of ratepayers, between (i) the forecast capital-related revenue requirement ("CRRR") that forms the basis of the C-factor, and (ii) the CRRR determined based on OPG's actual capital in-service additions for the prescribed hydroelectric facilities over the 2028-2031 period	Proposed to address a scenario in which the actual capital-related revenue requirement determined based on OPG's actual in-service amounts for the prescribed hydroelectric facilities is less than the capital-related revenue requirement provided through the payment amounts inclusive of C-factor

Ratemaking Element	2017-2021 Ratemaking Method (EB-2016-0152)	2027-2031 Proposal	Summary of Differences from EB-2016-0152
Earnings Sharing and Off-ramps	A regulatory review may be initiated if OPG's annual reporting shows performance outside of the ±300 basis points ROE dead band, or if performance erodes to unacceptable measures. No earnings sharing mechanism.	A regulatory review may be initiated if OPG's annual reporting shows performance for OPG's combined regulated nuclear and regulated hydroelectric operations outside of the ±300 basis points ROE dead band, or if performance erodes to unacceptable measures. Earnings sharing mechanism shares 50% of any regulated earnings for OPG's combined regulated nuclear and regulated hydroelectric business that exceed 100 basis points above the OEB-approved ROE rate, assessed over a cumulative 5-year period.	No change in ±300 basis points ROE dead band. Proposed continuation of earnings sharing mechanism approved in EB-2020-0290

The following information is provided in this schedule:

- Section 2.2 describes OPG's proposed process for determining the 2027 forward test year revenue requirement and hydroelectric payment amount.
- Section 2.3 describes OPG's proposed annual adjustment mechanism, including a description of the I-factor (Section 2.3.1), X-factor (Section 2.3.2), C-factor (Section 2.3.3) and GRCF (Section 2.3.4). Section 2.3.5 discusses the GHCVA and its interaction with the annual adjustment mechanism and interaction with other variance accounts.

- Section 2.4 describes other elements of the proposed framework, including applicability of incremental and advanced capital modules, treatment of unforeseen events, continuing deferral and variance accounts, and off-ramps.

2.2 Forward Test Year

Consistent with the OEB's 4GIRM price-cap methodology, the proposed hydroelectric payment amount in the 2027 test year is determined on a cost of service basis. As detailed in Ex. I1-1-1, Table 1, the proposed 2027 revenue requirement is equal to $1,668.3M. For ease of reference, a simplified version of that table is presented below as Chart 2.

Chart 2 – Summary of 2027 Hydroelectric Revenue Requirement

Line No.	Description	Reference to Ex. I1-1-1	2027 ($M)
1	Depreciation	Table 1, line 15	215.4
2	Cost of Capital	Table 1, line 12	634.2
3	Income Tax	Table 1, line 20	27.3
4	**Capital-Related Revenue Requirement**	**Sum lines 1 to 3**	**877.1**
5	OM&A	Table 1, line 13	499.3
6	GRC	Table 1, line 14	352.2
7	Property Tax	Table 1, line 16	2.1
8	Other Revenues	Table 1, line 19	(62.2)
9	**Total Revenue Requirement**	**Sum lines 4 to 8**	**$1,668.3**

The 2027 hydroelectric payment amount is determined by dividing the $1,668.3M proposed revenue requirement by the proposed 2027 hydroelectric production forecast of 32.5 TWh (Ex. E1-1-1, Table 1, line 4, col. (I)). This calculation results in a 2027 hydroelectric payment amount of $51.39/MWh.

2.3 Annual Adjustment Mechanism

For the years 2028-2031, the Application proposes that the hydroelectric payment amount be adjusted annually according to a mechanistic custom price-cap adjustment, using the following formula:

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

Where:

- HPA_{2027} = 2027 hydroelectric payment amount determined in Section 2.2
- "I" represents generation-industry inflation, determined annually based on a composite inflation index recommended by London Economics International LLC ("LEI"), using the same indices that the OEB uses to adjust rates for electricity distributors. As in 4GIRM and in OPG's previously approved price cap mechanism for the prescribed hydroelectric facilities, the Application proposes that the I-factor value would be adjusted mechanistically as part of an annual payment amounts adjustment application. LEI calculated a 2023 I-factor value of 3.6% using the most recent Statistics Canada data at the time of conducting its analysis.
- "X" is the sum of:
  - a productivity factor, and
  - a stretch factor determined by econometric total cost benchmarking of OPG's prescribed hydroelectric generation facilities.
- "C" is a Custom Capital Factor, designed to recover incremental revenue each year necessary to support substantial incremental capital investments required over the forecast period, beyond the amount of revenue that would be recovered through the I – X adjustment alone.
- "GRCF" is a GRC Factor, designed to hold the GRC expense embedded in payment amounts constant over the IR term.

2.3.1 Inflation Factor

OPG retained LEI to recommend an appropriate inflation factor for the company's hydroelectric price cap framework. LEI's analysis is attached to this schedule as Attachment 1.[12] LEI recommended continuing the application of the composite index previously approved for use in OPG's 2017-2021 hydroelectric price cap methodology, including the use of the natural log function to calculate the annual growth rate, as directed by the OEB in its EB-2016-0152 Decision and Order.[13]

The composite index uses the same sub-indices that the OEB uses when determining the inflation factor for electricity distributors under 4GIRM:

- Canadian Gross Domestic Product Implicit Price Index – Final Domestic Demand ("GDP-IPI FDD") from Statistics Canada; and
- Average Weekly Earnings for Ontario – Industrial Aggregate ("Ontario AWE") from Statistics Canada.

Continued use of the above composite index is consistent with the following principles:

- Simplicity
  - Macroeconomic measures that have been approved for use by the OEB for electricity distribution, natural gas distribution, and OPG's regulated hydroelectric generation
  - Easy to calculate and understand
  - Relies on publicly available data
- Relevance to OPG's costs
  - Relevance to unit cost pressures is best achieved with a composite input-based inflation index
  - Represents the basic categories of inputs (labour, non-labour)
- Stability
  - Relatively stable indices over time.

[12] See Attachment 1: Analysis of Inflation Factor Options for OPG's Regulated Hydroelectric Business.
[13] Decision and Order, EB-2016-0152, December 28, 2017, p. 123.

LEI's analysis produced the following weightings between capital and OM&A costs in Chart 3:

Chart 3 – Summary of Hydroelectric I-Factor Weighting[14]

Sub-Index	Weight Assigned
Capital	75.4%
OM&A – Non-labour	9.3%
Total (GDP-IPI FDD)	**84.7%**
OM&A – Labour	15.3%
Total (Ontario AWE)	**15.3%**

Based on labour and non-labour sub-index values published by the OEB in June 2025, OPG has assumed an I-factor of 3.49% in its pre-filed evidence. OPG proposes to make annual adjustments for inflation on the same basis as approved by the OEB in EB-2016-0152.[15] Sub-indices and their weighting would remain constant in each year; only the value of each sub-index would change.

2.3.2 X Factor

OPG proposes an X-factor composed of two elements: (i) an industry productivity factor, as calculated by LEI's TFP study of the North American hydroelectric generation industry, and (ii) a stretch factor based on OPG's hydroelectric benchmark performance.

2.3.2.1 Productivity Factor

LEI's TFP Study[16] yields a productivity factor between -0.40% and -1.01%.[17] However, for the reason described below, OPG is proposing a productivity factor of zero in this Application.

OPG retained LEI to prepare a hydroelectric generation industry productivity study for OPG's prescribed hydroelectric assets. LEI was responsible for identifying appropriate methodologies

[14] See Attachment 1: Analysis of Inflation Factor Options for OPG's Regulated Hydroelectric Business.
[15] Decision and Order, EB-2016-0152, December 28, 2017, p. 121.
[16] Ex. A1-3-2, Attachment 2.
[17] Ex. A1-3-2, Attachment 2, p. 6.

of data compilation and peer selection as well as analyzing the data. This subsection summarizes LEI's methodology, the peer group selected, and the study's conclusion. The TFP Study, provided as Attachment 2, describes and explains LEI's analysis and conclusions in greater detail.

The TFP Study includes both a "physical approach" and "monetary approach" of measuring the hydroelectric industry's productivity growth. This dual-approach responds to the OEB's guidance in its Decision and Order in EB-2016-0152, in respect of the TFP Study that LEI prepared in support of OPG's hydroelectric rate-setting framework in that application (the "2016 TFP Study"). In its EB-2016-0152 Decision and Order, the OEB approved of various aspects of LEI's physical approach, such as using generation (in megawatt hours, "MWh") to measure the generation industry's output, but was not prepared to completely accept it over the monetary approach that Pacific Economics Group Research LLC employed in the study that it had prepared for OEB Staff.[18]

LEI describes the overall difference between the two methods as follows:

> "The physical approach uses physical indicators such as installed capacity in megawatts ("MW") to produce an estimate that reflects the quantity of capital employed to generate electricity, while the monetary method estimates capital input quantity through depreciated asset values in constant dollar terms."[19]

While the physical and monetary approaches use different methods of measuring input quantities, both are ultimately intended to measure the same relationship: the total quantity of a firm's outputs relative to the quantity of inputs it employs.[20] As noted above, LEI found that both methods identify a negative productivity growth trend in the North American hydroelectric generation industry.

[18] Decision and Order, EB-2016-0152, December 28, 2017, pp. 126-128.
[19] Ex. A1-3-2, Attachment 2, p. 8.
[20] Ex. A1-3-2, Attachment 2, pp. 49-55.

The selection of inputs and outputs is a critical element in the design of the TFP Study. To ensure meaningful and reliable results, the input data must accurately reflect how outputs are produced in the industry and be supported by readily available, quantifiable data.

LEI selected two inputs for its TFP analysis – one representing capital inputs, and another that represents non-capital inputs (namely, total operations and maintenance expenditures ("O&M") measured in dollars and deflated by an input price index). Under the physical method, LEI measured capital input quantities using physical capital (the installed capacity of hydroelectric generating facilities), measured in MW, and readily available across time and companies. For the monetary method, LEI used depreciated asset values in constant dollar terms as the input quantity of capital. For the output, LEI used generation, measured in MWh, which offers both a direct link to productivity and the advantage of consistent, industry-wide reporting. Generation data is readily available for all hydroelectric generators and is measured in a standardized manner across companies. LEI also found that generation is the most commonly used output measure in academic and regulatory benchmarking studies, reinforcing its suitability for use in TFP analysis.

LEI established an appropriate industry peer group using a multi-dimensional set of criteria, with the goal of identifying comparable utilities while accounting for data availability constraints. Consistent with the approach used in the 2016 TFP study, LEI focused primarily on firms with medium (500–1,000 MW) or large (>1,000 MW) total hydroelectric capacity. To broaden the dataset, LEI also included additional peers with smaller fleet sizes (<500 MW), provided they met other screening criteria. Eligible peers were required to operate more than one hydroelectric plant and, ideally, have an average fleet age comparable to OPG's prescribed hydroelectric assets. A key requirement was the availability of hydroelectric-specific operational data over the full 2002-2023 study period.

LEI considered seven Canadian utilities for inclusion in the industry peer group but, despite a number of efforts, was ultimately unable to obtain sufficient data on hydroelectric-specific O&M

expenses for the full 2002-2023 study period.[21] As a result, no other Canadian utilities were included in the final industry peer group used in the TFP Study, which peer group consisted of US peers.

LEI calculated TFP results using a trend regression approach, which reduces any endpoint bias in the calculation of an average growth over time, and looked at both physical and monetary measures of capital input. The results of the TFP Study are summarized in Chart 4. For the full peer group consisting of 20 US peers plus OPG, using data from 2002-2023, LEI calculated the TFP growth rate to be -0.40% per annum using a physical measure of capital input and the trend regression method of estimating the TFP growth rate. For the monetary approach, a slightly reduced peer group was used due to data availability issues. Under this approach, LEI calculated a TFP growth rate of -1.01% per annum using the trend regression method. For comparison purposes, if LEI had used the same reduced peer group for the physical approach as for the monetary approach, the TFP growth rate would have been -0.61%.

Chart 4 – Summary of Hydroelectric TFP Results

Measure of Capital Input	Peer Group	TFP Growth Rate
Physical	20 US peers plus OPG	-0.40%
Physical	16 US peers plus OPG	-0.61%
Monetary	16 US peers plus OPG	-1.01%

Within the study conclusion, LEI observed that a negative TFP growth in the hydroelectric sector is not unusual and should not be interpreted as a sign of inefficiency. Unlike distribution utilities, which often see output growth as their customer base expands, hydroelectric generators typically maintain steady output over time. However, inputs such as maintenance and capital investments tend to increase as assets age, in order to preserve the physical capability of the assets and operational performance. This relationship across fixed productive

[21] LEI pursued multiple avenues to access the required information, including Statistics Canada and NERC databases, annual reports, regulatory filings, and other publicly available sources. In addition, LEI submitted information requests directly to all seven utilities. Despite these efforts, the necessary data was not made available.

capability, fixed capital stock, and increasing operating and maintenance costs naturally leads to negative productivity growth.

Notwithstanding the results of the TFP Study, which indicate a negative productivity trend of -0.40% to -1.01%, OPG has elected to apply a productivity factor of zero in this Application. This approach is consistent with OEB policy and past precedent. In the electricity distribution context, the OEB has explicitly declined to embed negative productivity expectations into rate-setting. As stated in its Report on the Distribution Productivity Factor under the RRF, the OEB "does not believe it appropriate for a rate-setting regime to project and entrench declining productivity expectations into the future."[22] Similarly, in its EB-2016-0152 Decision and Order, the OEB found that "a base productivity factor of 0%, as proposed by OPG, is appropriate for OPG's hydroelectric IRM plan".[23]

While OPG maintains that the negative TFP results from the LEI study accurately reflects industry trends, OPG also acknowledges the OEB's policy position. By proposing a productivity factor of zero, OPG effectively accepts an incremental 0.40% to 1.01% stretch relative to observed TFP performance. As a result, OPG's hydroelectric business will be required to outperform the industry trend identified by LEI in order to achieve the lower rates produced under the proposed hydroelectric price-cap index adjustment.

2.3.2.2 Stretch Factor

OPG proposes to use a 0.15% stretch factor based on OPG's performance in the econometric analysis conducted by LEI, and specifically on the OM&A and sustaining capital spending benchmarking model, which was the more expansive approach of the two methods developed by LEI. A copy of LEI's hydroelectric cost benchmarking report is filed as Attachment 3 to this schedule.

[22] EB-2010-0379, Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors, p. 17.
[23] Decision and Order, EB-2016-0152, December 28, 2017, p.128.

As described in this section, OPG arrived at its proposed stretch factor by adopting the range of stretch factors used in the OEB's 4GIRM methodology (i.e., 0%, 0.15%, 0.3%, 0.45%, and 0.6%) and identifying a stretch factor that corresponds with the company's hydroelectric benchmarking performance.

LEI utilized two econometric models to assess OPG's hydroelectric benchmarking performance. The first model benchmarks OM&A costs and captures annual operations, maintenance, and administration expenses, including non-recurring, project-related OM&A expenses (the "OM&A Model"). The second model benchmarked the combined OM&A costs and sustaining capital expenditures ("OM&A + SC Model"). This approach is guided by the OEB's EB-2016-0152 Decision and Order, in which the OEB stated that it "expects OPG to continue to examine whether additional costs should be benchmarked for the purposes of future stretch factors."[24] The OM&A + SC Model incorporates both ongoing OM&A expenses and annual capital expenditures related to sustaining plant capability. Both models use data points over a four-year time horizon for 253 plants owned by 13 hydroelectric generating companies, including OPG. Chart 5 provides a summary of OPG's benchmarking results under each model.

Chart 5 – Summary of OPG Hydroelectric Cost Benchmarking Performance

	OM&A Model	OM&A + SC Model
OPG Quintile Results	First	Second
Corresponding OEB Stretch Factor	0.0%	0.15%

As described in Section 3.3 of the report, LEI did not include environmental and regulatory costs, land and water rental fees, or capital investments related to plant improvements and expansions. Environmental and regulatory costs are mandatory and largely outside of management's control, as are land and water rental fees. Capital investments associated with enhancing plant capability tend to be large, infrequent, and highly dependent on a utility's specific position within its investment cycle. LEI notes that including these types of expenditures in an econometric analysis over a fixed, relatively short time horizon could

[24] Decision and Order, EB-2016-0152, December 28, 2017, pp. 129-130.

introduce distortions, as not all peer companies would have incurred comparable capital costs during the study period.

The benchmarking results place OPG in the first quintile within the OM&A Model and in the second quintile within the OM&A + SC Model, indicating strong relative performance overall. In this Application, OPG has adopted the higher stretch factor resulting from the OM&A + SC Model, as it captures a broader range of the "steady state" cost drivers in OPG's hydroelectric business, resulting in a 0.15% stretch factor.

2.3.3 C-Factor

OPG proposes a C-factor designed to recover total revenue sufficient to support the need for ongoing investments for ensuring the long-term availability and reliability of OPG's aging hydroelectric assets. The C-factor allows OPG to maintain the efficiency incentives of the price-cap approach used to set base hydroelectric payment amounts, while also recovering incremental capital-related revenue requirement associated with the significant investments required at the facilities over the 2027-2031 period. The C-factor incorporates a 0.15% stretch factor reduction for all capital-related revenue requirement, providing an ongoing efficiency incentive for OPG's regulated hydroelectric capital costs.

The C-factor calculation is detailed in Ex. I1-2-1, Table 2 and is demonstrated in Chart 6, Chart 7, and Chart 8, below, with each of the steps described thereafter. OPG proposes that the C-factor be set for the rate term at the fixed percentage amounts determined in this proceeding.

Chart 6 – 2027-2031 Hydroelectric Capital-Related Revenue Requirement and 2028-2031 Incremental Hydroelectric Capital Funding Requirement

Line No.	Description	Note	2027	2028	2029	2030	2031
1	Depreciation	Determined on a cost-of-service basis	215.4	228.4	249.6	263.6	271.7
2	Cost of Capital		634.2	681.2	766.6	816.3	855.7
3	Income Tax*		27.3	70.3	87.6	101.6	110.7
4	**Capital-Related Revenue Requirement**	**Sum lines 1 to 3**	**876.9**	**979.9**	**1,103.8**	**1,181.5**	**1,238.1**
5	Stretch Factor			0.15%	0.15%	0.15%	0.15%
6	Capital-Related Revenue Requirement Stretch Adjustment	line 4 x line 5 (cumulative)		1.5	3.1	4.9	6.8
7	**Capital-Related Revenue Requirement (after stretch adjustment)**	**line 4 - line 6**	**876.9**	**978.5**	**1,100.7**	**1,176.6**	**1,231.4**
8	Capital funding provided through (I-X)**, *assuming C-Factor application in preceding years*	(line 8_{t-1} + line 9_{t-1}) x (I-X) See further details below.	876.9	906.2	1,011.1	1,137.5	1,215.9
9	**Incremental Capital Funding Requirement**	**line 7 - line 8 See further details below.**	**0.0**	**72.2**	**89.6**	**39.1**	**15.5**

* Income Tax is provided for all five years and included within the calculation of the Incremental Capital Funding Requirement above, on the basis that Income Tax expense is predominantly (though not entirely) capital-related.

** This analysis assumes an I-factor of 3.49% based on the proposed labour and non-labour weightings and the sub-index values published by the OEB in June 2025. As discussed in section 2.3.1, OPG is proposing to update the sub-index values annually.

Chart 7 – 2027-2031 Formula-Derived Non-Capital Revenue Requirement

Line No.	Description	Note	2027	2028	2029	2030	2031
1	OM&A	Escalated by (I-X)	501.4	518.2	535.5	553.3	571.8
2	GRC	Fixed at 2027 amount	352.2	352.2	352.2	352.2	352.2
3	Other Revenues	Escalated by (I-X)	(62.2)	(64.3)	(66.5)	(68.7)	(71.0)
4	**Total Non-Capital Revenue Requirement**	**Sum lines 1 to 3**	**791.4**	**806.1**	**821.2**	**836.9**	**853.1**

Chart 8 – Determination of 2028-2031 C-Factor

Line No.	Description	Note	2027	2028	2029	2030	2031
1	Capital-Related Revenue Requirement (after stretch adjustment)	Chart 6, line 7	876.9	978.5	1,100.7	1,176.6	1,231.4
2	Total Non-Capital Revenue Requirement	Chart 7, line 4	791.4	806.1	821.2	836.9	853.1
3	**Total Revenue Requirement**	**line 1 + line 2**	**1,668.3**	**1,784.5**	**1,921.9**	**2,013.4**	**2,084.4**
4	Incremental Capital Funding Requirement	Chart 6, line 9	0.0	72.2	89.6	39.1	15.5
5	**Custom Capital Factor**	**line 4 / line 3_{t-1}**		**4.3%**	**5.0%**	**2.0%**	**0.8%**

The C-factor is the percentage change in the total revenue requirement attributable to capital investment that is not otherwise recovered from customers through the I-X adjustment. The factor, shown in Chart 8, line 5, is determined through the following steps demonstrated above:

1. Determine capital-related revenue requirement (Chart 6, lines 1-4). This is based on a forecast of depreciation, cost of capital, and income taxes requirements during the 2027-2031 period.
2. Reduce by stretch factor (Chart 6, lines 5-7). The capital-related revenue requirement is reduced by the stretch factor of 0.15%. The C-factor is designed to recover this capital-related revenue requirement net of the stretch factor adjustment.
3. Determine capital-related revenue requirement recovered through (I-X) price-cap adjustment (Chart 6, line 8). The 2027 cost of service capital-related revenue requirement is used as the starting point, with 2028-2031 amounts determined by escalating the prior-year amount by (I-X). Note that this is an iterative process with Step 4, as discussed in Step 5.
4. Determine incremental capital funding requirement (Chart 6, line 9). The difference between the capital-related revenue requirement in Chart 6, line 4 and the revenue

requirement determined by escalating by (I-X) in Chart 6, line 8 represents the shortfall faced by OPG's prescribed hydroelectric facilities if the payment amounts were set using a price-cap index methodology without a custom C-factor for that year. Note that this is an iterative process with Step 3, as discussed in Step 5.

5. Iterative process for Steps 3 and 4 (Chart 6, line 8). Determination of the capital funding at line 8 and incremental capital funding requirement at line 9 is an iterative process. The 2028 capital funding at line 8 is determined by multiplying 2027 capital-related revenue requirement by (I-X). This provides for a value of $906.2M. Given the capital-related revenue requirement (after stretch) is $978.5M, there is an incremental capital funding requirement of $72.2M in 2028, as presented in line 9. For determining the 2029 provided-for capital funding at line 8, it is assumed that the $72.2M funding requirement from 2028 is reflected in the 2028 payment amount, such that the (I-X) is applied to the sum of $906.2M and $72.2M (equivalent to the amount at line 7). This results in the 2029 capital funding at line 8 of $1,011.1M, and incremental capital funding requirement at line 9 of $89.6M. This process is repeated for 2030 and 2031.
6. Determine non-capital revenue requirement for 2028-2031 (Chart 7). OM&A and Other Revenue is determined by escalating 2027 amounts by (I-X). GRC is held constant by implementing a GRC adjustment factor as discussed in Section 2.3.4.
7. Determine custom capital factor (Chart 8). The C-factor is calculated by dividing the incremental capital funding requirement (Chart 8, line 4) by the prior year's total revenue requirement (Chart 8, line 3).

2.3.4 GRC Factor

OPG proposes that the hydroelectric Custom IR framework include the GRCF, a custom factor that removes the (I-X) escalation of GRC amounts embedded in payment amounts, lowering annual payment amounts relative to a comprehensive price-cap adjustment. OPG believes that the GRCF is an appropriate adjustment in the context of a Custom IR framework that is also designed, through the C-factor, to recover incremental capital-related revenue requirement associated with the significant investments required in the IR term. The GRC reflects the fact that GRC is payable by OPG, as an owner of hydroelectric generating stations, using a prescribed, non-escalating formula pursuant to *Electricity Act, 1998* and related

regulations (Ex. F1-4-1, Section 3.0). OPG proposes that the GRCF be set for the rate term at the fixed percentage amounts determined in this proceeding.

Similar to the determination of the C-factor described in Section 2.3.3, the calculation of the GRCF first considers the GRC funding provided through the (I-X) formula. To remove this escalation, the GRCF is calculated by dividing the additional GRC funding provided through (I-X) by the prior year's total revenue requirement, and multiplying the result by -1. This calculation is detailed in Ex. I1-2-1, Table 2, Note 2 and reproduced in Chart 9 below.

Chart 9 – Determination of 2028-2031 GRCF

Line No.	Description	Note	2027	2028	2029	2030	2031
1	GRC provided through (I-X)	(line 1 + line 2) x (I-X)	352.2	364.0	364.0	364.0	364.0
2	Variance to 2027 GRC	line 1 less $352.2M	0	(11.8)	(11.8)	(11.8)	(11.8)
3	Total Revenue Requirement	Chart 8, line 3	1,668.3	1,784.5	1,921.9	2,013.4	2,084.4
4	**GRCF**	**line 2 / line 3_{t-1}**	**0**	**-0.7%**	**-0.7%**	**-0.6%**	**-0.6%**

2.3.5 Global Hydroelectric Capital Variance Account and Capacity Refurbishment Variance Account

OPG proposes a GHCVA that would address a scenario where the capital-related revenue requirement determined based on OPG's actual capital in-service amounts for the prescribed hydroelectric facilities over the 2028-2031 period is less than the capital-related revenue requirement afforded through the payment amounts inclusive of the C-factor. The proposed account is asymmetric in favour of ratepayers and would be evaluated in aggregate on a cumulative basis over the last four years of the IR term.

GHCVA Operation

The proposed account would record the difference, for the 2028-2031 period, between (i) the forecast capital-related revenue requirement ("CRRR") that forms the basis of the C-factor, and (ii) the CRRR determined based on OPG's actual capital in-service additions for the prescribed hydroelectric facilities.[25] The account would be asymmetric in that an amount could be credited to ratepayers in the event the CRRR determined based on actual capital in-service additions over the period is less than the CRRR that forms the basis of the C-factor. In the event the CRRR based on actual capital in-service additions is greater than the CRRR underpinning the C-factor, there would be no recovery from ratepayers through this account. Two illustrative examples are provided below to demonstrate this relationship.

In scenario 1, the CRRR determined based on the actual capital in-service additions over the 2028-2031 period exceeds the forecast CRRR underpinning the C-factor, as presented in Chart 10 below.

Chart 10: GHCVA Scenario 1 – Actual CRRR is Greater than Forecast

Line No.	Description	Note	2028	2029	2030	2031	Total
1	Forecast Capital-Related Revenue Requirement (after stretch adjustment)	Chart 6, line 7	978.5	1,100.7	1,176.6	1,231.4	
2	Illustrative Actual Capital-Related Revenue Requirement	Illustrative only	988.5	1,110.7	1,186.6	1,241.4	
3	Variance: Actual CRRR less Forecast CRRR	line 2 - line 1	10	10	10	10	40
4	**GHCVA Disposition to Ratepayers**	**Lesser of line 3 and $0**					**0**

In this scenario, the CRRR based on illustrative actual capital in-service additions over the period exceeds the forecast CRRR underpinning the C-factor by $10M in each year between 2028 and 2031 (Chart 10, line 3). As this account is proposed to be asymmetric in favour of ratepayers, there would be no recovery from the account in this scenario. Instead, as shown

[25] The GHCVA would not apply to the 2027 year as there would be no C-factor for that year.

at line 4, the lesser of $40M (the total difference over the period) and $0 results in $0 dispositioned to ratepayers.

In scenario 2, CRRR determined based on actual capital in-service additions over the 2028-2031 period does not exceed the forecast CRRR underpinning the C-factor, as presented in Chart 11.

Chart 11: GHCVA Scenario 2 – Actual CRRR Less than Forecast

Line No.	Description	Note	2028	2029	2030	2031	Total
1	Capital-Related Revenue Requirement	Chart 6, line 7	978.5	1,100.7	1,176.6	1,231.4	
2	Illustrative Actual Capital-Related Revenue Requirement	Illustrative only	968.5	1,090.7	1,166.6	1,221.4	
3	Variance: Actual CRRR less Forecast CRRR	line 2 - line 1	(10)	(10)	(10)	(10)	(40)
4	**Disposition to Ratepayers**	**Lesser of line 3 and 0**					**(40)**

In this scenario, the CRRR based on illustrative actual capital in-service additions is less than the CRRR underpinning the C-factor by $10M in each year between 2028 and 2031 (Chart 11, line 3). In line 4, the lesser of a $40M credit (the total difference over the period) and $0 results in a $40M credit balance being dispositioned to ratepayers.

The request for the GHCVA is found in Ex. H1-1-1, Section 7.2.

CRVA Operation and Interaction with GHCVA

As discussed in Ex. H1-1-1, Section 5.6, OPG is proposing to continue the CRVA that was originally established in EB-2007-0905, pursuant to O. Reg. 53/05, section 6(2)4, and approved in all subsequent OPG applications. The CRVA records the financial impacts of variances between the actual capital and non-capital costs and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a prescribed generation facility and those forecast costs and firm financial commitments underpinning the revenue requirement approved by the OEB. With the proposed C-factor designed to recover

the forecast CRRR that includes CRVA-eligible projects, the Application proposes that, in respect of capital costs for the prescribed hydroelectric facilities, the CRVA record the difference, for the 2027-2031 period, between (i) the actual annual revenue requirement impact of the eligible projects, and (ii) the forecast revenue requirement impact of the eligible projects as reflected in the forecast CRRR underpinning the C-factor.

Given the capital-related nature of both the CRVA and the proposed GHCVA, OPG has considered the interaction between the two.

OPG has identified two possible interactions to be addressed. The first interaction involves a capital-related net credit entry in the CRVA, which could also drive a credit entry in the GHCVA for the same variances. To address such duplication, it is proposed that any such capital-related credit entries in the CRVA reduce any credit entries in the GHCVA. This adjustment would be applied on the same four-year timeframe as the GHCVA calculations (i.e., with respect to any CRVA capital-related credit entries accumulated over the 2028-2031 period). This interaction is illustrated in Chart 12 below. Furthermore, if the CRVA has a capital-related net credit entry at the same time as no entry to the GHCVA due to the actual CRRR exceeding the forecast CRRR underpinning the C-factor, there would be no amount refundable in respect of the CRVA.

Chart 12: Interaction with CRVA if Actual CRRR Less than Forecast and Credit in CRVA

Line No.	Description	Note	Total
1	Illustrative GHCVA disposition to ratepayers	Chart 11, line 4	(40)
2	Illustrative Capital-Related CRVA balance available for disposition	Illustrative-only	(20)
3	**Illustrative GHCVA balance available for disposition**	**line 1 - line 2**	**(20)**

In this case, ratepayers are still credited the full amount of $40M related to the CRRR based on actual capital in-service amounts being less than the CRRR underpinning the C-factor. The credit of $40M is split between $20M in the CRVA and $20M in the GHCVA.

The second interaction involves a capital-related net debit entry to the CRVA that could arise at the same time as no entry to the GHCVA due to the actual CRRR exceeding the forecast CRRR underpinning the C-factor. To limit the CRVA recovery from ratepayers in these circumstances, it is proposed that any such capital-related debit entries in the CRVA be recoverable only if there is no credit balance in the GHCVA and only up to the amount that the actual CRRR exceeds the CRRR underpinning the C-factor. This adjustment would be applied on the same four-year timeframe as the GHCVA calculations. This interaction is illustrated in Chart 13 below.

Chart 13: Interaction with CRVA if Actual CRRR Greater than Forecast and Debit in CRVA

Line No.	Description	Note	Total
1	Actual CRRR less Forecast CRRR	Chart 10, line 3	40
2	Illustrative Capital-Related CRVA balance	Illustrative-only	50
3	**CRVA balance available for disposition**	**Lesser of line 1 and line 2**	**40**

Given the interaction between the two accounts, the capital-related CRVA entries for the prescribed hydroelectric facilities for the 2028-2031 period would be evaluated in aggregate on a cumulative basis over the last four years of the IR term, at the same time as the GHCVA.

Interaction between Tax-Related Accounts and GHCVA

As discussed in Ex. H1-1-1, Section 7.3 and Ex. F4-2-1, Section 3.6, the Application is proposing a Clean Electricity ITC Variance Account (OPG) to record the revenue requirement impact of Clean Electricity investment tax credits (“CEITCs”) received by OPG for eligible investments in the prescribed facilities. As discussed in that evidence, the revenue requirement impact of CEITCs will be realized through a reduction to rate base and associated reductions to depreciation expense and cost of capital, and the resulting tax effects of the capital-related changes. As discussed in Ex. H1-1-1, Section 5.5, the Income and Other Taxes Variance Account (OPG) is proposed to continue recording the financial impact on OPG’s revenue requirements of various changes in tax rates and rules, as well as tax assessments and re-

assessments. As discussed in Ex. H1-1-1, Section 5.20, the Application proposes that the variance between actual and forecast Scientific Research & Experimental Development investment tax credits for the prescribed hydroelectric facilities be recorded in the SR&ED ITC Variance Account. Collectively, these three accounts are referred to as "tax-related accounts" in this evidence. As noted in Ex. H1-1-1, the tax-related accounts would record their corresponding impacts without duplication to each other or with the amounts recorded in the CRVA.

There is potential for overlap between entries in the tax-related accounts and the GHCVA. As noted, entries to the GHCVA are determined by comparing CRRR based on the actual capital in-service additions against the forecast CRRR underpinning the C-factor. Potential CEITCs received or other tax-related changes subject to the tax-related accounts over the 2028-2031 period may result in a credit (or an increase to the credit) balance in the GHCVA. The Application proposes that each of these tax-related accounts operate independently of the GHCVA and record their corresponding actual impacts relative to the forecasts reflected in the forecast CRRR underpinning the C-factor, as they would in the absence of the GHCVA. For purposes of the GHCVA, it is proposed that the actual CRRR be normalized for the capital-related impacts recorded in the tax-related accounts for the prescribed hydroelectric facilities over the 2028-2031 period. In the event of such a capital-related net credit entry to a tax-related account, the CRRR would be increased by the absolute value of such entry in the tax-related account. In the event of a capital-related net debit entry in a tax-related account, the CRRR would be decreased by the absolute value of such entry. This approach helps ensure that the revenue requirement impact of tax-related changes will not be duplicated across the tax-related accounts and the GHCVA. For clarity, it is this CRRR adjusted for the tax-related account entries that would be used in the assessment of the interaction between the GHCVA and CRVA discussed above.

3.0 PRESCRIBED NUCLEAR FACILITIES RATE-SETTING PROPOSAL

3.1 Overview of Nuclear Custom IR Proposal

The Application proposes that payment amounts for the nuclear facilities continue to be set based on the Custom IR framework approved in EB-2016-0152 and continued in EB-2020-

0290, as adjusted for the DNNP facilities to reflect the business context of the program and DNNP LP. The framework is based on five individual annual nuclear revenue requirements over the IR term, upon which are layered incremental, benchmark-based stretch reductions for OPG's regulated nuclear facilities. This approach is sustained year-over-year, creating a meaningful incentive to continuously improve performance and cost efficiency during the period. The adjustments to the Custom IR framework proposed for the DNNP facilities are discussed in Section 3.2 below, including that stretch factors should not apply to these facilities during this IR term.

Consistent with the direction in O. Reg. 53/05, s. 14(2)7, this Application is requesting blended nuclear payment amounts for OPG's regulated nuclear facilities and the DNNP facilities. The formula for determining the blended payment amount for each year of the five-year rate term is as follows:

$$(A + B) / (C+D)$$

where

"A" is the OEB-approved nuclear revenue requirement for OPG's nuclear facilities

"B" is the OEB-approved revenue requirement for the DNNP facilities

"C" is the OEB-approved production forecast for OPG's nuclear facilities

"D" is the OEB-approved production forecast for the DNNP facilities.

The previously approved Custom IR framework is based on the principles set out in the RRF and the OEB's prior guidance on incentive ratemaking. The nuclear Custom IR framework is tied to OPG's performance on Total Generating Cost per MWh ("TGC/MWh") benchmarking that underlies the company's gap-based business planning process. The proposed Custom IR framework applies elements of incentive rate-setting – in particular, a benchmark-based stretch factor to OPG's regulated facilities – in a manner that is compatible with OPG's business context.

Chart 14 summarizes the elements of the proposed nuclear Custom IR framework, along with major corresponding policy objectives from the Handbook, the RRF, and other sources. While the Handbook had not been issued when OPG filed the prior EB-2016-0152 rate-setting

application, the OEB found that the Custom IR proposal in that proceeding generally met the standards for such applications as set out in the Handbook.[26]

Chart 15 – Summary of Nuclear Custom IR Framework

Policy Objective(s)	Source	Corresponding Aspect(s) of Nuclear Custom IR Framework
Term Adopt a longer-term approach to payment amount-setting based on the parameters for a multi-year Cost of Service application and a Custom IR framework	IR Report, p. 9 OEB Letter of February 17, 2015 O. Reg. 53/05[27] Handbook, p. 25	Nuclear ratemaking proposal includes five future test years with individual forecast revenue requirements, subject to a cumulative stretch factor reduction for each year beginning in the second year, 2028, for OPG's regulated nuclear facilities.
Benchmarking Include meaningful efficiency incentives derived from external benchmarking	RRF, p. 17 Handbook, p. 26	Stretch factor reduction of OPG's nuclear revenue requirements provide up-front benefits to customers.
Operational Effectiveness Provide tangible benefits and consequences for operating performance Encourage sustainable, year-over-year efficiency gains	IR Report, p. 9 RRF, p. 59 Handbook, p. 10	Stretch reductions persist year-over-year, incenting OPG to find further savings in each year of the IR term beginning in 2028. The 100% variable rate design of the payments means that failure to achieve production forecast or to manage operating costs and capital expenditures has direct financial consequences for the companies, creating a meaningful incentive to continuously improve productivity.

[26] Decision and Order, EB-2016-0152, December 28, 2017, p. 136.
[27] O. Reg. 53/05, s. 6(2)12.

Policy Objective(s)	Source	Corresponding Aspect(s) of Nuclear Custom IR Framework
Outcomes & Performance Measurement Be aligned with performance outcomes Performance measures should be directly linked to desired performance outcomes	RRF, pp. 3, 59 Handbook, p. 10, 26	The Application is proposing an OEB performance scorecard to provide meaningful measures of performance of the nuclear operations. The proposed measures reflect identified RRF performance outcomes. See Section 3.0 below. The scorecard will include all of the measures used in OPG's nuclear benchmarking for its regulated facilities. Application includes robust evidence of the nuclear operations and project forecasts.
Customer Focus Robust planning, informed by customer preferences and driven by benefits to customers, with appropriate pacing and prioritization to control costs and manage risks A focus on cost-effective delivery of outcomes that matter to customers	Handbook, pp. 10, 26	The rate-shaping framework proposed in Ex. I1-3-2 was informed by a customer engagement process. Details of the customer engagement process are provided in Ex. A2-2-1.
Protecting Customers	RRF, p. 11 Handbook, pp. 27-28	The ROE-based off-ramp applies to the achieved ROE for OPG's combined regulated nuclear and regulated hydroelectric operations. Earnings sharing mechanism shares 50% of any regulated earnings for OPG's combined regulated nuclear and regulated hydroelectric business that exceed 100 basis points above the OEB-approved ROE rate, assessed over a cumulative five-year period.

As described above, this Custom IR framework remains appropriate for the 2027-2031 rate period for OPG's nuclear facilities, during which the costs and production levels will continue to vary due particularly to the PRP (Ex. D2-3-1). It is also appropriate for the DNNP facilities, with certain modifications discussed in Section 3.2 below, particularly as they are not forecasted to have any production until Unit 1 enters commercial operation in late 2030 (Ex. D2-4-1).

As set out in EB-2016-0152 and EB-2020-0290, the nuclear Custom IR framework balances the objectives of the RRF and other policies described above with the fact that OPG and DNNP LP's capital and operating costs will vary significantly over the next five years. The Custom IR reflects the volatility in the underlying nuclear costs during this period, while still creating meaningful, benchmark-based incentives to continuously improve OPG's nuclear cost performance.

3.2 Stretch Factor Proposal for OPG's Regulated Nuclear Facilities

The nuclear stretch factor is proposed to reduce OPG's regulated nuclear revenue requirement in respect of the company's operations OM&A costs (the sum of Base, Project, Outage, and Pickering Cyclical Maintenance OM&A), allocated corporate support OM&A costs and asset service fees, as well as the capital-related revenue requirement excluding the Darlington Refurbishment Program ("DRP") and the PRP. The stretch factor also would not apply to OPG's OM&A costs related to the PRP.

As discussed in Section 3.2.1 below, this Application proposes a 0.3% stretch factor for OPG's 2028-2031 costs. The stretch reduction is cumulative, resulting in a greater reduction to the applicable portion of OPG's nuclear revenue requirement in each successive year of the IR term.

Consistent with the prior two nuclear Custom IR frameworks, the Application proposes that the OEB continue to exclude costs related to the major refurbishment programs from the calculation of the stretch factor. Like the DRP, the PRP is a discrete investment that has been established by provincial energy system planning, with detailed planning, a defined budget, and specific cost-recovery requirements under O. Reg. 53/05. Accordingly, it remains appropriate to exclude

these investments from the calculation of the stretch factor. This treatment is consistent with the EB-2016-0152 Decision with Reasons and the EB-2020-0290 OEB-approved Settlement Proposal.[28]

Given the nature and timelines of the DNNP expenditures, the Application proposes that it would not be appropriate to apply a stretch factor to costs associated with the DNNP facilities. Similar to the DRP and the PRP, the DNNP is a large, singular investment to build a new nuclear facility that will not be in "steady state" operations during the IR term. In keeping with the treatment of the DRP and PRP costs, it would not be appropriate to apply a stretch factor, as there would be no "steady state" functions in which to drive incremental efficiency gains. Furthermore, it would be impossible to calculate a stretch factor that meaningfully captures the relative cost efficiency of the DNNP facilities before they have been in operation. DNNP Unit 1 is forecast to enter service in late 2030, near the end of the IR term. There is no performance history or other basis on which to conduct a cost benchmarking study (nor is it evident how the relative cost efficiency of the facility could be determined, given the new reactor technology and lack of operating peers). Further details on OPG's cost and schedule commitments for these projects can be found in Ex. D2-3-1 and related evidence (for the PRP) and Ex. D2-4-1 and related evidence (for the DNNP).

OPG continually strives to improve the company's performance and operational efficiency where it can do so safely within operational and regulatory requirements and without affecting reliability. OPG develops certain initiatives to meet these goals for its regulated nuclear facilities through the gap-based nuclear business planning process described in Ex. F2-1-1.

3.2.1 Derivation of Proposed Stretch Factor for OPG's Facilities

OPG proposes to calculate the nuclear stretch factor based on the historic normalized TGC/MWh of the Darlington Nuclear Generating Station, as set out in the independent expert Nuclear Cost Performance Benchmarking report prepared by ScottMadden and filed as Attachment 4 to Ex. F2-1-1. This is because the Pickering Nuclear Generating Station is not

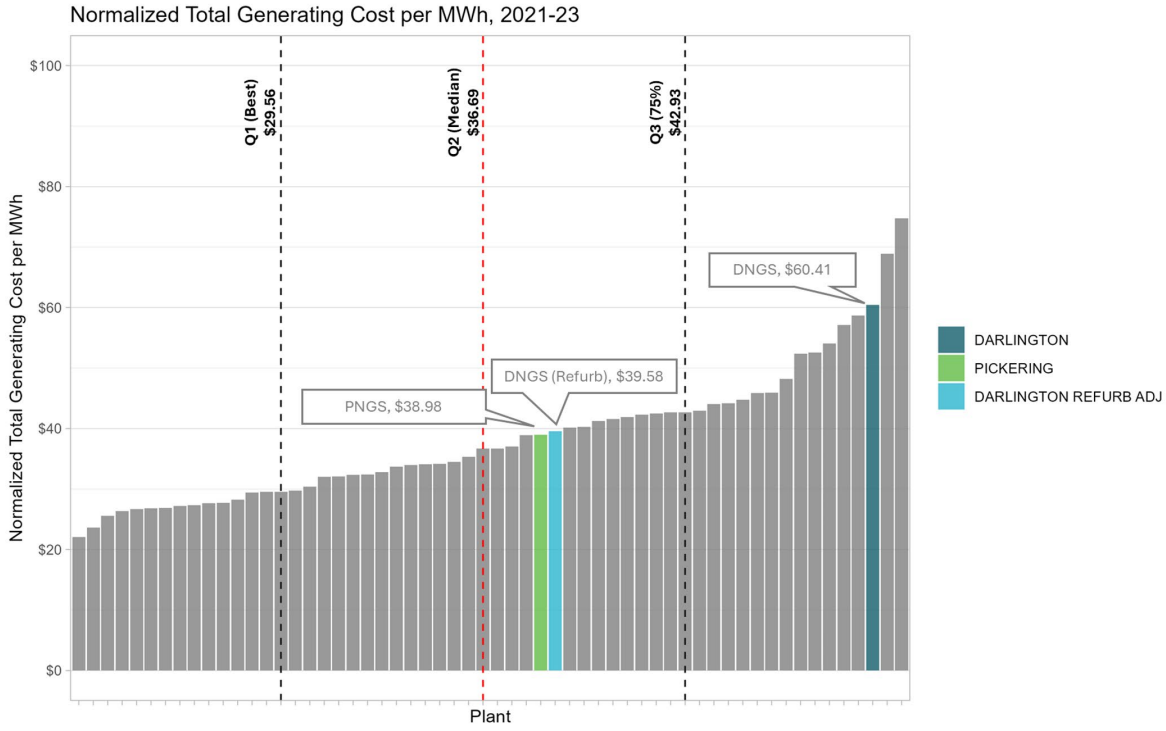
[28] Decision and Order, EB-2016-0152, December 28, 2017, pp. 140-141; Decision and Order, EB-2020-0290, November 15, 2021, Schedule A, p. 32.

forecast to produce electricity until partway through 2031, when the first unit is scheduled to return to service.

As shown in Chart 16 below, ScottMadden's econometric analysis concludes that the TGC/MWh of Darlington over the 2021-2023 historic period was $39.58, once the impacts of the DRP and planned outages are accounted for. This performance puts the station in the median or third quintile of the Electric Utility Cost Group ("EUCG") peer group.[29] Accordingly, OPG proposes a nuclear stretch factor of 0.3% based on the range of stretch factors set out by the OEB in the RRF.

Chart 16 – Normalized TGC/MWh

(ScottMadden Nuclear Cost Performance Benchmarking Report)[30]



[29] ScottMadden's methodology divides the peer group nuclear plants into quartiles rather than quintiles. The median range can be calculated taking the half-way points between the median value ($36.69) and the first quartile ($29.56) and between the median value and the fourth quartile ($42.93). This produces a median quintile range of between $33.13 and $39.81.

[30] Ex. F2-1-1, Attachment 4, p. 10.

The normalized three-year TGC/MWh used to determine performance for stretch factor purposes is based on ScottMadden's independent expert methodology. As described in detail in Ex. F2-1-1 Attachment 4, ScottMadden uses an econometric methodology to quantify the relationships between various aspects of the peer nuclear generating stations. Their approach used multiple linear regression to quantify the relationships between factors including reactor type, capacity, unit age, and other variables and the total generating cost of the plants. They use these relationships to develop a predictive model, helping compare a wide range of plants despite varied reactor technologies, capacities, and age. On top of this econometric analysis, ScottMadden normalized their findings to account for the impact of planned outages and, critically, the costs associated with the DRP.

The refurbishment-normalized TGC/MWh of Darlington over the 2021-2023 period is the appropriate metric upon which to calculate the nuclear stretch factor for the forecast period in this application, as it most closely approximates the relative cost-efficiency of the station relative to the peer group.

3.2.2 Proposed Stretch Reduction Amounts for OPG's Facilities

Consistent with the approach approved by the OEB in prior OPG applications, annual stretch reductions are calculated such that the prior years' reductions are maintained (i.e., reductions to revenue requirement made in 2028 are carried forward to subsequent years, on the presumption that the company should be incented to find additional savings each year).[31]

Chart 16 shows the result of applying the proposed stretch factor to forecast Nuclear Operations, corporate Support Services OM&A and asset service fees, as well as the Nuclear Operations and Support Service capital-related revenue requirement (i.e., excluding the DRP and PRP). The details of these calculations can be found in Ex. I1-3-1, Table 2.

[31] This is the approach that the OEB approved and used to set nuclear payment amounts in EB-2016-0152 and EB-2020-0290.

Chart 17 – Stretch Reduction Amounts for 2028-2031 ($M)

	2028	2029	2030	2031
OM&A (Base, Project, Outage, Pickering Maintenance, and Allocated Corporate Support OM&A)	$1,607.2	$1,792.6	$1,727.7	$2,022.6
Asset Service Fees	$73.9	$89.5	$99.0	$99.4
Nuclear Operations and Support Services Capital-Related Revenue Requirement	$679.9	$790.3	$843.9	$958.2
Stretch Factor	0.30%	0.30%	0.30%	0.30%
Annual Stretch Reduction to Nuclear Revenue Requirement	**$7.1**	**$15.1**	**$23.1**	**$32.4**

The total reduction over the term of the application is $77.7M.

This stretch reduction is incremental to the performance improvements required to achieve OPG's Business Plan. Customers will benefit from these "up-front" budget reductions, and OPG will bear the risk of any shortfall during the IR term.

3.2.3 Productivity Factor Continues to be Inapplicable

Consistent with the OEB's approval in the EB-2016-0152 Decision and Order, and the EB-2020-0290 OEB-approved Settlement Proposal, the Application is not proposing a nuclear industry productivity adjustment as part of the proposed stretch factor.[32] The nature and scale of the work planned for the IR term – in particular the ongoing PRP and DNNP – means that past productivity trends would not be a reasonable indicator of predicted productivity during the IR term.

[32] Decision and Order, EB-2016-0152, p. 138.

4.0 OTHER ELEMENTS OF CUSTOM IR PROPOSALS

In this section, OPG addresses several other elements of the proposed Custom IR frameworks.

4.1 Earnings Sharing Mechanism

In EB-2020-0290, the OEB-approved Settlement Proposal introduced an earnings sharing mechanism as part of OPG's rate-setting framework. The approved mechanism is based on the performance of OPG's combined regulated nuclear and regulated hydroelectric businesses 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. To effectuate the earnings sharing mechanism, the OEB approved an Earnings Sharing Deferral Account, effective January 1, 2022, to record 50% of any regulated earnings for OPG's combined regulated nuclear and regulated hydroelectric business that exceed 100 basis points above the OEB-approved ROE rate on the above basis.

The Application proposes to continue the earnings sharing mechanism for OPG's regulated facilities over the 2027-2031 period. Consistent with the mechanism approved in EB-2020-0290, OPG proposes to base the earnings sharing mechanism on its combined regulated 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 2027-2031. As noted in Ex. C1-1-1, Section 3.0, the Application proposes to establish the ROE for the IR term using the prevailing ROE specified by the OEB in accordance with the OEB's Decision and Order, Generic Proceeding – Cost of Capital and Other Matters (EB-2024-0063). In pre-filed evidence, the Application incorporates 9.11% as this is the latest rate published by the OEB pursuant to the ROE formula as set out in EB-2024-0063. To effectuate the proposed earnings sharing mechanism for OPG's regulated facilities, the Application proposes to continue the existing operation of the Earnings Sharing Deferral Account (see Ex. H1-1-1, Section 5.26).

Given that DNNP Unit 1 is forecast to be placed in service late in the fourth year of the five-year IR term and is subject to the DNNPDVA (see Ex. H1-1-1, Section 6.1), no earnings sharing mechanism is proposed for the DNNP LP in this IR term.

4.2 Off Ramp

Each year, OPG is required to file an analysis of the actual annual regulatory return, after tax on rate base, both dollars and percentages, for its combined regulated business (i.e., both hydroelectric and nuclear).[33] This analysis includes a comparison of the regulated business' achieved ROE against the approved ROE included in the payment amounts. The Application proposes that this reporting requirement continue to be the basis for determining if OPG's actual ROE is outside the +/-300 basis point trigger established by the RRF for determining whether a regulatory review may be initiated.

The Application proposes to implement an equivalent reporting requirement for an analysis of the actual annual regulatory return, after tax on rate base, both dollars and percentages, for DNNP LP's regulated business beginning with the year that DNNP Unit 1 is placed in service. This information would be the basis of determining whether a regulatory review as set out above may be initiated for DNNP LP. Consistent with the analysis performed by OPG for its combined regulated business, the DNNP LP analysis would reconcile between accounting earnings and achieved ROE for its regulated operations.

4.3 Unforeseen Events & Regulatory Materiality Threshold

The Application proposes that unforeseen events affecting OPG's regulated hydroelectric and nuclear businesses continue to be addressed through an accounting order process, subject to a $20M regulatory materiality threshold. Subject to the updated materiality threshold, this approach is consistent with the accounting order application requirements currently in place for accounting changes impacting the calculation of OPG's nuclear liabilities and changes in depreciation end-of-life dates for the prescribed nuclear facilities.[34] The proposed materiality threshold is an increase from the $10M materiality threshold that OPG has historically applied, in some capacity since at least EB-2010-0008,[35] and which was most recently accepted for this purpose in the EB-2016-0152 Decision and Order[36] and EB-2020-0290 approved settlement

[33] Decision and Order, EB-2016-0152, p. 146, and EB-2020-0290, Ex. O-1-1, Appendix A., p. 1.
[34] EB-2016-0152 Payment Amounts Order, p. 13 and EB-2020-0290 Payment Amounts Order, p. 8. In this Application, OPG proposes to update this requirement to reflect a $20M materiality threshold.
[35] Decision with Reasons, EB-2010-0008, March 10, 2011, p. 124.
[36] Decision and Order, EB-2016-0152, December 28, 2017, pp. 134, 142.

proposal.[37] The proposed increase in the regulatory materiality threshold is consistent with threshold increases reflected in OPG's updated filing requirements and general inflationary impacts over time.[38]

For the DNNP facilities, a $10M regulatory materiality threshold is proposed, reflecting the lower rate base and revenue requirement requested for the DNNP facilities in this IR term, relative to the regulated OPG facilities.[39]

5.0 PERFORMANCE SCORECARDS AND OTHER REPORTING

OPG files an annual performance scorecard with the OEB, including a suite of performance metrics on both its prescribed nuclear and prescribed hydroelectric generating facilities. Since the OEB's Decision and Order in EB-2016-0152, such measures reported to the OEB have remained relatively consistent and the Application proposes to maintain a similar set of measures for OPG's performance scorecards over the 2027-2031 IR term. A discrete performance reporting proposal for the DNNP is set out in Section 5.3 below.

OPG's hydroelectric and nuclear scorecards each cover a five-year historical period. The most recent historical scorecards are provided as Attachments 4 and 5 to this schedule for the regulated hydroelectric and nuclear facilities, respectively.[40] For most measures, the scorecards include targets for the most recent historical year and the current year (in Attachments 4 and 5, these are 2024 and 2025, respectively). OPG would continue to file nuclear benchmark reporting annually, once available, that will discuss the facilities' performance on each metric.[41] Along with the hydroelectric scorecard, OPG would continue to file a Management Discussion and Analysis that would discuss the performance of its prescribed hydroelectric facilities for the most recent year.

[37] Decision and Order, EB-2020-0290, November 15, 2021, Schedule A, p. 17.
[38] For example: Filing Requirements for Ontario Power Generation Inc., pp. 14-15.
[39] Basing a materiality threshold on a percentage of rate base and revenue requirement is consistent with past practice, as discussed, for example, in EB-2016-0152 Ex. L-CCC-47.
[40] As noted in section 5.1 below, the 2024 hydroelectric scorecard includes the Environmental Performance Index as a Safety & Environment measure. As of 2026, OPG proposes to replace this measure with Total Recordable Environmental Events, as defined below.
[41] The current version of OPG's nuclear benchmark reporting is filed as Ex. F2-1-1, Attachment 2.

Historically, OPG has filed preliminary nuclear scorecard metrics and the hydroelectric scorecard metrics by April 30 each year. OPG proposes to maintain this timing for both scorecards in the IR term. OPG would continue to file final nuclear scorecard metrics and benchmark quartile results by November 30 each year.

Except as noted below, OPG's proposed scorecard incorporates the current nuclear and hydroelectric performance reporting measures, per the OEB-approved settlement of EB-2020-0290. The scorecard performance measures are consistent with the Operational Effectiveness outcomes contemplated in the RRF, including measures of reliability, cost performance, safety, and environmental performance. These measures reflect outcomes that are both meaningful to customers and important inputs to the company's business planning processes. Additional detail on the performance measures is discussed in Sections 5.1 and 5.2 below.

In addition to the nuclear and hydroelectric scorecards, OPG currently provides an annual report on the DRP pursuant to the Reporting and Recordkeeping Requirements set out in Appendix A of the OEB-approved Settlement Proposal in EB-2020-0290, as well as certain other periodic reporting. The Application's proposal with respect to the DRP, PRP, and DNNP project reporting is discussed in Section 5.3. For the other periodic reporting, the Application proposes to maintain such reporting currently in place for OPG as outlined in Section 5.4 below, subject to minor adjustments indicated therein.

5.1 OPG's Hydroelectric Scorecard Performance Measures

OPG proposes to continue reporting the annual hydroelectric performance measures approved by the OEB in EB-2016-0152 and in EB-2020-0290, updated to reflect changes to safety and environmental performance reporting (as discussed in Ex. F1-1-1, Section 4.0).

Chart 18: Annual Hydroelectric Performance Measures

Hydroelectric Performance Metrics	
Category	**Measure**
Safety & Environment	Total Recordable Injury Frequency (per 200k hours)
	Total Recordable Environmental Events (#)
Reliability	Availability Factor (%)
	Equivalent Forced Outage Rate (%)
Cost-Effectiveness	OM&A Unit Energy Cost ($/MWh)
	Total Generating Cost per Net MWh ($/MWh)

Total Recordable Injury Frequency (per 200k hours) ("TRIF"): TRIF is measured and reported for OPG's Renewable Generation ("RG") business as a whole, which includes regulated and unregulated facilities.

Total Recordable Environmental Events ("TREE"): Beginning in 2026, RG is revising its environmental performance measure (previously Environmental Performance Index) to track and report the number of spills and regulatory infractions. This change resulted from the completion of the legislated Polychlorinated Biphenyl equipment removal program, which historically formed part of the Environmental Performance Index; going forward, OPG will continue to report on spills and regulatory infractions, which also formed part of the EPI metric. TREE is measured and reported for OPG's RG business as a whole, which includes regulated and unregulated facilities.

Availability Factor: The Availability Factor is a measure of time a generating unit is capable of providing service, regardless of whether or not it is actually in service. Availability Factor is measured for the regulated hydroelectric fleet.

Equivalent Forced Outage Rate ("EFOR"): EFOR is an indicator of generating unit reliability measured by the ratio of time the unit was forced out of service (completely or partially) to the total time the unit was operating and forced out of service (completely or partially). EFOR is measured for the regulated hydroelectric fleet.

OM&A Unit Energy Cost: This metric measures the OM&A costs (Base and Project OM&A) per unit of energy produced. It excludes the GRC because it is determined by provincial regulation and therefore not within the direct control of OPG. OM&A Unit Energy Cost is measured for the regulated hydroelectric fleet.

Total Generating Cost per Net MWh: This metric measures total cost of operating the regulated hydroelectric facilities, encompassing operations, maintenance and administration (OM&A), fuel (water) and sustaining[42] capital, divided by total generation (MWh). To mitigate the impact of year-over-year fluctuations in capital expenditures, TGC is measured as a three-year historical average. Consistent with prior OEB-approved scorecards, there is no target for TGC. TGC is measured for the regulated hydroelectric fleet.

5.2 OPG's Nuclear Scorecard Performance Measures

OPG proposes to continue reporting the annual nuclear performance measures approved by the OEB in EB-2016-0152 and in EB-2020-0290.

OPG's scorecard aligns the actual performance for each measure with the basis on which the performance target is set. Unless otherwise noted on the scorecard, targets and actual performance are reported on a single-year basis. For example, since the Nuclear Performance Index ("NPI") targets are calculated using a two-year rolling average for Pickering and a three-year rolling average for Darlington, the scorecard presents the actual performance for NPI for the same periods.

OPG would include in the scorecard the company's normalized TGC/MWh and normalized TGC per Unit for its prescribed nuclear facilities, using the updated methodology as presented in Ex. F2-1-1, Section 3.3, Chart 3.[43] As described in the preceding section, this metric provides the most accurate, comparable view of the value-for-money provided by the nuclear stations. OPG would also continue reporting on the non-normalized TGC/MWh.

[42] Redevelopment projects are excluded from TGC.
[43] With the shutdown of Units 1 and 4 and the transition to refurbishment for Units 5-8, a TGC/MWh metric will not be provided for Pickering until the first full year of post-refurbishment operations for at least one unit.

OPG would continue filing separate performance results for the two nuclear stations. In addition, OPG would provide combined nuclear performance results for Unit Capability Factor, Nuclear Performance Index, and TGC/MWh.

5.3 Major Project-Specific Performance Reporting

Similar to its historic reporting on the status of the DRP, the Application proposes to issue annual public reports on the status of both the PRP and the DNNP.

For the PRP, OPG plans to publish annual public status reports on its website for the duration of the program. These reports will provide insights into key performance indicators, including construction progress, cost and schedule performance, and safety metrics. Details of the proposed PRP reporting are set out in Ex. D2-3-9, Section 7.

Annual status reports on the DNNP will be issued to the public for the duration of the program. This reporting will include a range of measures, including construction completion, cost performance, schedule performance, and safety performance. Details of the proposed DNNP reporting are set out in Ex. D2-4-9, Section 8.

5.4 Other Reporting

5.4.1 Other OPG Reporting

In addition to the reporting proposed above, OPG proposes to continue the following other periodic reporting to the OEB. OPG proposes to maintain these requirements for the 2027-2031 IR term, filed at the same frequency and timing as in the current rate period, except as noted below:

- Unaudited balances of deferral and variance accounts within 60 days after calendar quarter-end for the first three quarters, and within 90 days for December year-end balances (a proposed increased from 60 days currently);
- The Management Discussion and Analysis and financial statements as filed with the Ontario Securities Commission within 60 days for the first three quarters, and within 120 days for December year-end statements as long as the Ontario Securities Commissions requires these documents to be filed;

- Nuclear unit capability factors and hydroelectric availability for the regulated facilities within 60 days for the first three quarters and within 120 days for December year-end as reported in OPG's quarterly and annual MD&A;
- Full-Time Equivalent information by April 30 each year;
- Capital in-service additions and construction work-in-progress by April 30 each year;
- An analysis of the actual annual regulatory return, after tax on rate base, dollars for the regulated business as a whole and separately for its regulated nuclear and hydroelectric business segments, and a percentage for the regulated business based on OPG's approved capital structure, and a comparison with the regulatory return included in the payment amounts by July 31 of each year;
- Annual report on expenses related to nuclear liability by June 30;
- Pickering Closure Costs Deferral Account annual reporting by April 30 of each year on amounts recorded broken down by the major categories in O. Reg 53/05 Section 5.6 with no reporting of such amounts until cumulative balance exceeds $50M;

As noted above, OPG proposes that the timing of filing unaudited balances of deferral and variance accounts be increased to within 90 days after quarter-end for the fourth quarter to better align with OPG's financial reporting timelines. OPG finalizes and published year-end financial statements in March, making it more challenging to prepare this information under the current timing requirements.

Pursuant to the OEB-approved Settlement Proposal in EB-2020-0290, OPG currently provides extensive hourly information related to hydroelectric surplus baseload generation ("SBG").[44] Pursuant to the EB-2023-0336 settlement agreement, in support of future requested clearances of the SBG Variance Account, OPG also files, as part of its pre-filed evidence, the same information as set out in EB-2023-0336, Ex. L-H-SEC-04, Attachment 1 and in Ex. L-H-SEC-05, Attachment 1 (together with other information). On the basis that such reporting at the time

[44] Annual reporting by June 30: 1) all SBG claimed amounts including total MW on an hourly basis by each regulated facility, and the calculation of these amounts booked in the Hydroelectric Surplus Baseload Generation Variance Account; 2) information in relation to usage of the Sir Adam Beck Pump Generating Station as provided in EB-2020-0290 Ex. JT2.22, revised to an hourly resolution.

of clearing account balances is similar to the current annual report requirements, and is voluminous, OPG proposes to discontinue the annual reporting requirements.

OPG also proposes to discontinue reporting of a supplementary calculation that divides OPG's actual dollar regulatory return for each regulated business segments by 45% of the corresponding rate base, which is currently being provided alongside the actual annual regulatory return reporting pursuant to the above settlement proposal. OPG does not believe this reporting is meaningful as OPG's deemed capital structure is established on an overall basis.

All proposed reporting would continue to be posted on OPG's website for public access, redacted as necessary for confidentiality reasons.

5.4.1 Other DNNP LP Reporting

For the DNNP facilities, the Application proposes the following reporting by DNNP LP in addition to the DNNP major project-specific reporting discussed above:

- Annual audited financial statements within 120 days of the December year-end;
- Unaudited balances of deferral and variance accounts within 60 days after the first, second, and third calendar quarter-end and 90 days after the fourth calendar quarter-end;
- Capital in-service additions and construction work in progress by April 30 each year; and
    - An analysis of the actual annual regulatory return, after tax on rate base, both dollars and as a percentage for the regulated business, and a comparison with the regulatory return included in the payment amounts by July 31 of each year.

LIST OF ATTACHMENTS

Attachment 1:	*Analysis of Inflation Factor Options for OPG's Regulated Hydroelectric Business*, London Economics International LLC
Attachment 2:	*Empirical Analysis of Total Factor Productivity Trends in the North American Hydroelectric Generation Industry*, London Economics International LLC
Attachment 3:	*Benchmarking the Costs of Hydroelectric Generation Companies in North America*, London Economics International LLC
Attachment 4:	2024 Hydroelectric Facilities Performance Scorecard
Attachment 5:	2024 Nuclear Facilities Performance Scorecard

LONDON ECONOMICS

London Economics International LLC

Analysis of Inflation Factor Options for OPG's Regulated Hydroelectric Business

prepared for
Ontario Power Generation

Julia Frayer
Stella Mueller
Barbara Porto
Juan Carlos Segovia

Content as of June 2025

For the inflation factor, LEI recommends continuing the use of the Ontario AWE/Canada GDP-IPI FDD composite index given precedence, relevance, and stability

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- **LEI analyzed three options:**
  1) Economy-wide inflation index
  2) Current composite input price index composed of Ontario Average Weekly Earnings ("AWE") and Canada Gross Domestic Product Implicit Price Index for Final Domestic Demand ("GDP-IPI FDD")
  3) More complex composite input price index
- **Top reasons for continuing with Ontario AWE/Canada GDP-IPI FDD composite input index:**

1. Precedence and simplicity

- Macroeconomics measure that has been approved by the Ontario Energy Board ("OEB") for electricity distribution, natural gas distribution, and hydroelectric generation
- Use of similar composite index accepted by regulators and ratepayers across Canada
- Easy to calculate and understand
- Relies on publicly available data

2. Relevance to OPG's costs

- Relevance to OPG's unit cost pressures is best achieved with a composite input-based inflation index
- Represents the basic categories of inputs (labour, non-labour)

3. Index stability

- Relatively stable index over time

- **LEI recommends updating the weighting of the indices based on the industry average input cost shares from the current LEI TFP Study, which has been filed as a separate report**

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How is inflation applied in an incentive rate-setting methodology ("IRM")?

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- **OPG asked LEI to recommend an appropriate inflation factor ("I-factor") for an I-X IRM approach for OPG's prescribed hydroelectric assets**

> **Economists use the term 'inflation' to denote an *"ongoing rise in the general level of prices quoted in units of money"***
>
> Source: Lawrence H. White, "Inflation." *The Concise Encyclopedia of Economics*. 2008. Library of Economics and Liberty.

- **Under the total factor productivity ("TFP")-based I-X approach, an I-factor is needed to reflect inflationary pressures on costs**
  - Rates change per the I-X formula annually
  - The choice of the I-factor also impacts the X-factor (for example, if an economy-wide based measure is used)
- **During the IRM period, the I-factor will be updated periodically, based on the <u>actual</u> inflation trend for the previous period**
  - Application of the previous period I-factor results in a lag for cost reflection in rates, the severity of which depends on when data is published and magnitude of inflation pressures
  - We cannot know what the inflation values will be in the future, but we can assess viability of different indices by looking at longer term historical trends
- **In IRM regimes around the world, both composite input price indices and economy-wide indices have been used**

Ontario has used both economy-wide measures and composite industry-specific input inflation indices through different generations of IRM for electricity distributors

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1GIRM (2001-2006)

Input Price Index ("IPI") – weighted average of 3 components: price of labour, price of materials, and price of capital (applied to all utilities)

- Labour based on utility's line crew wage rate published by the Municipal Electric Association, materials based on Statistics Canada's ("StatCan") Industrial Product Price Index ("IPPI"), and capital based on a user-cost of capital approach
- Given volatility, only 50% of price of capital was accounted for in the IPI

2GIRM (2007-2009)

GDP-IPI FDD – broad macroeconomic (output) measure, takes into account cost of capital equipment; less controversial and easier to implement

3GIRM (2009-2013)

GDP-IPI FDD – OEB recognized that there may be differences in input price trends for the industry and the broader economy; however, for simplicity assumed that the Input Price Differential ("IPD") was zero

4GIRM (2014-)

Choice of 3 regulatory options with 2 inflation index options:

- 4G Incentive Ratemaking – **composite input price index**
- Custom Incentive Ratemaking – **composite input price index** or **economy-wide measure, based on OEB's inflation analysis**
- Annual Incentive Ratemaking Index – **composite input price index**

For the composite index, the OEB decided on a 2-factor approach, using **Ontario AWE for the labour sub-index and Canada GDP-IPI FDD for the non-labour sub-index**, as the capital sub-index was found to be overly volatile

Natural gas distributors have mostly used the GDP-IPI economy-wide input price index for the I-factor

In the 2017 Decision, OEB adopted LEI's recommended composite input price index for the I-factor in OPG's first-generation hydroelectric payment amounts ("HPA")

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- **A composite inflation index is built from an arrangement of sub-indices that reflect inflation trends for different inputs/cost categories**

$$I = \alpha\,(Labour\ inflation) + \beta\,(Non-labour\ inflation) + \delta\,(Capital\ inflation)$$

$$where\ \alpha, \beta, and\ \delta\ represent\ weights$$

- **Relevance to OPG's unit cost pressures is best achieved with a composite input price index**
  - The two-index composite for OPG is similar to the two-factor inflation index in 4GIRM for electricity distributors
  - OEB's recent decisions also indicate a preference for composite input-focused inflation indices
- **A single consumer price index ("CPI") (output-based) or producer price index ("PPI") (input-based) could be used as the I-factor, but LEI recommended an I-factor based on more specific inflation indices that represent inflationary pressures for different inputs to OPG's hydroelectric business**
  - No single PPI exists for hydroelectric generators
  - If utilizing an economy-wide output-based inflation measure like CPI, an IPD between the Canadian economy and the hydroelectric industry must be calculated and accounted for in setting the X-factor; OEB has typically assumed IPD = 0%
  - LEI also recommended that the I-factor be applied to all costs in base rates, including the Gross Revenue Charge ("GRC") and capital-related charges (depreciation, etc.)

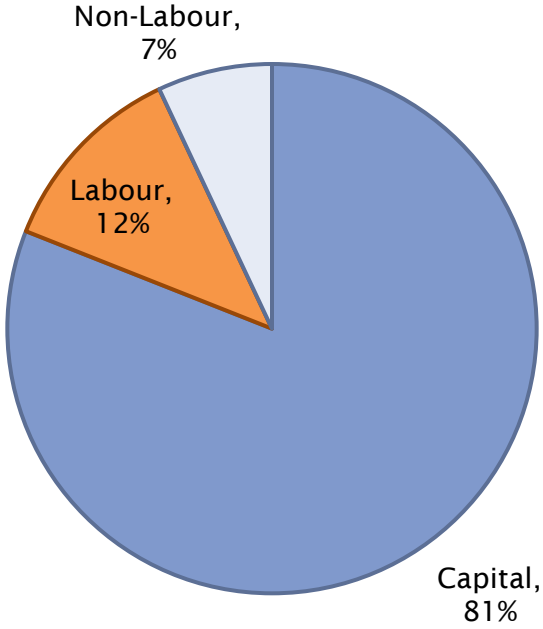
In the 2017 Decision, OEB accepted LEI's recommended weighting of 88% for capital and non-labour and 12% for labour, based on input cost shares from the LEI TFP Study

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- **88%/12% was an industry average weight (not OPG-specific) for non-labour and labour**
- **An industry average weight ensures an exogenous I-factor that is representative of industry conditions**
  - Using industry trends over firm-specific trends has OEB precedent
- **Using the same capital, labour, and non-labour shares for the I-factor as in the TFP study ensures consistency in the overall escalation mechanism**

Labour: 12%

*Operations and maintenance ("O&M") industry average from TFP study (2002-2012) * Electric Utility Cost Group ("EUCG") industry labour share*



Capital & Non-Labour: 88%

Capital weight: *Industry average from TFP study (2002-2012)*

Non-labour weight: *O&M industry average from TFP study (2002-2012) * EUCG industry non-labour share*

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At the time of the 2017 Decision, OPG's I-factor was calculated to be in the range of 1.7% based on trends observed for prior years

- **I-factor was calculated using the following formula:**

I = 12%(labour inflation) + 7%(non-labour inflation) + 81%(capital inflation)

	Capital & Non-Labour (GDP-IPI FDD – National)							Labour (AWE – Ontario)			Index
	Q1	Q2	Q3	Q4	Annual	Annual % change	Weight	Annual	Annual % change	Weight	Annual % change
2014	112.5	113.2	113.7	114.1	113.4			938.3			
2015	114.4	114.8	115.6	116.1	115.2	1.6%	88%	962.7	2.6%	12%	**1.7%**

- **Other key findings in the OEB's 2017 Decision related to the I-factor:**
  - OEB Staff identified small adjustments to the I-factor calculation with respect to using the natural log for the annual growth rate and rounding of data
  - OEB found it was appropriate to apply I-X to the GRC as it is determined based on gross revenue; certain parties argued that GRC should not be subject to I-X

Source: OEB. Docket EB-2016-0152. Decision and Order. December 28, 2017. Pages 122-123.

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LEI recommends continuing the use of six objective criteria to evaluate I-factor designs

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1. Relevance to utility costs

Does the index closely reflect the utility's observed cost pressures?

2. Exogeneity

Is the utility a large component of the index?

3. Source reliability

Does the index come from a reliable source?

4. Data availability

Does the index rely on readily available, public data?

5. Precedence and simplicity

Is the index generally accepted by regulators and ratepayers, and is it easy to calculate and understand?

6. Index stability

Are the year-over-year changes in the index relatively stable and not overly volatile?



Recent decisions by Canadian regulators reinforce the six objective criteria recommended by LEI

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- **OEB's I-factor for 2025 electricity distribution rate applications continues to reference the Renewed Regulatory Framework for Electricity ("RRFE") issued in 2013, which reinforces LEI's criteria**
  - Relevance & simplicity: "2-factor IPI can be implemented just as *easily* as the GDP-IPI (FDD), but provides a *better indication of Ontario input price fluctuations* than the economy-wide measure"
  - Source reliability & data availability: "the inflation factor must be constructed and updated using data that is *readily available from public and objective sources*"
  - Stability: "the 2-factor IPI achieves this *without introducing unreasonable volatility*"
- **Alberta Utilities Commission's ("AUC") third-generation performance-based regulation ("PBR3") decision (2024-2028) adjusts the I-factor calculation methodology slightly relative to the PBR2 approach, but continues to maintain the following characteristics**
  - Relevance: the I-factor "should be *indicative of the change in input prices* that the utilities are expected to experience"
  - Simplicity: the I-factor "should be transparent, *simple to calculate and easy to understand*"
  - Stability, availability, reliability, exogeneity: the I-factor "should *not be overly volatile* … must be *published on a regular basis* by a *reputable independent agency* … should *not be overly influenced by the utility itself*"
- **In FortisBC's 2024 annual PBR review, it refers to the British Columbia Utilities Commission's ("BCUC") 2014 PBR decision, which considered the following criteria**
  - Relevance: "*indicative of changes in inflationary pressures* that the utility expects to experience"
  - Availability & reliability: "*readily available* and published by a *reputable, independent agency*"
  - Simplicity: "transparent and *easy to understand*"
  - Stability: "reasonably *stable*"

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3	**Analysis of potential options**
4	LEI's recommendation

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LEI has considered several possible indices and composite options for OPG's I-factor

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- **LEI analyzed three options:**
  1) Economy-wide inflation index
  2) Current composite input price index composed of Ontario AWE and Canada GDP-IPI FDD
  3) More complex composite input price index

Sample of indices recently considered by other regulators in IRM regimes

Canada GDP-IPI FDD and Ontario AWE composite	Alberta CPI and Alberta FWI composite	BC CPI and BC AWE composite	GDP-PI	US CPI-NE
• OEB ✓ Electricity distributors (2025) ✓ Toronto Hydro (2025) ✓ Enbridge (2022) ✓ OPG hydroelectric generation (2017)	• Alberta Utilities Commission ✓ Local distribution companies (2023) ✓ Despite using an economy-wide inflation measure (CPI), assumes differentials are immaterial	• British Columbia Utilities Commission ✓ FortisBC multi-year PBR (2025-2027) ✓ CPI treated as an output-based measure*	• Massachusetts Department of Public Utilities ✓ All electric & gas utilities (2024) ✓ GDP-PI treated as an output-based measure*	• Vermont Public Utilities Commission ✓ Green Mountain Power (2023-2026)

* Requires input price differential and TFP differential adjustments in the X-factor

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Different indices used to measure inflation have differing trends and sensitivities to economic cycles

- **LEI reviewed available StatCan indices and selected the few relevant indices below for further analysis**
  - Other indices were rejected due to lack of precedent and/or relevance, data inconsistency, or high volatility

Economy-wide index focus

Inflation index	2002-2023 timeframe			2022-2023 growth
	2002-2023 avg growth	Min annual growth	Max annual growth	
Canada GDP-IPI FDD	2.2%	1.0%	6.3%	3.7%
Ontario GDP-IPI FDD	2.1%	0.9%	6.3%	3.5%
Ontario CPI	2.2%	0.4%	6.8%	3.8%

Capital index focus

Inflation index	2002-2023 timeframe			2022-2023 growth
	2002-2023 avg growth	Min annual growth	Max annual growth	
Canada IPPI	2.9%	-0.3%	17.3%	1.6%
Handy Whitman	3.6%	0.6%	10.9%	4.7%

Labour index focus

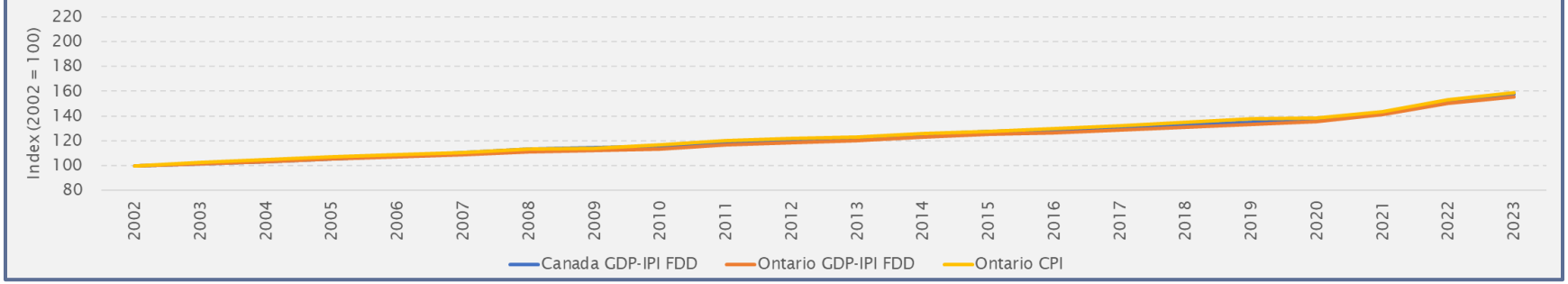
Inflation index	2002-2023 timeframe			2022-2023 growth
	2002-2023 avg growth	Min annual growth	Max annual growth	
Ontario AWE	2.3%	1.1%	7.3%	3.2%

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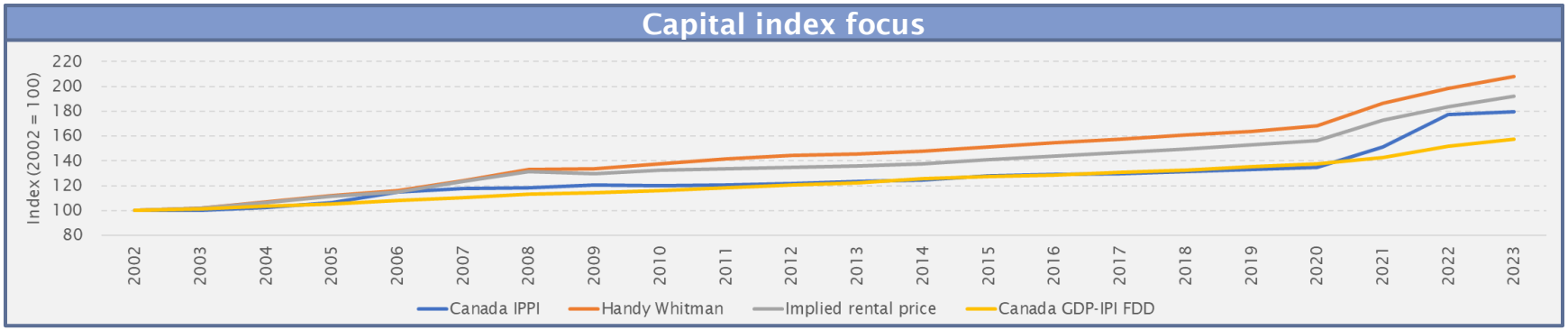
Capital input indices have demonstrated higher cumulative growth

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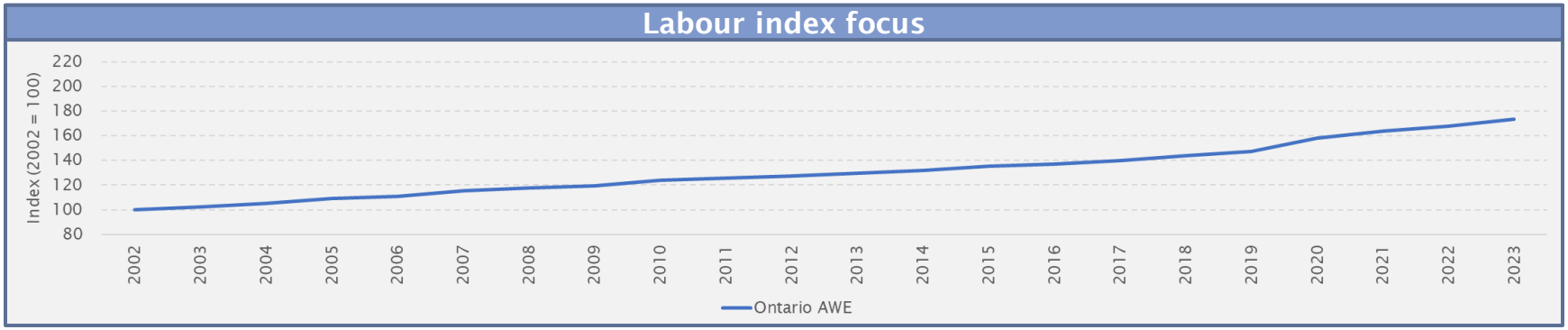
Economy-wide index focus



Capital index focus



Labour index focus



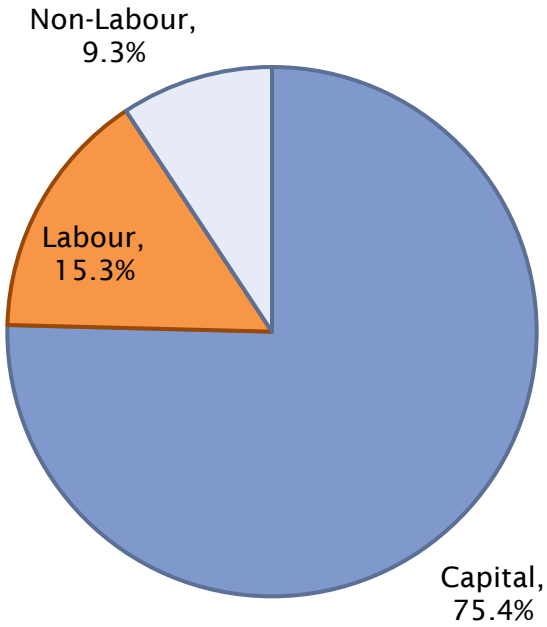
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LEI recommends updated weights for the sub-indices based on the industry average input cost shares from the current LEI TFP Study

- The I-factor weights approved in the OEB's 2017 Decision were 12% for labour inflation, 7% for non-labour inflation, and 81% for capital inflation
- Based on the updated industry average input cost shares from the current LEI TFP Study, the updated I-factor weights are 15.3% for labour inflation, 9.3% for non-labour inflation, and 75.4% for capital inflation

Labour: 15.3%

*Operations and maintenance ("O&M") industry average from TFP study (2002-2023) * Electric Utility Cost Group ("EUCG") industry labour share*



Capital & Non-Labour: 84.7%

Capital weight: *Industry average from TFP study (2002-2023)*

Non-labour weight: *O&M industry average from TFP study (2002-2023) * EUCG industry non-labour share*

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3 Analysis of potential options

Option 1: Economy-wide inflation index

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A single economy-wide inflation index would theoretically require adjustment to the X-factor, which the OEB has discounted in the past

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- **Canada GDP-IPI FDD in 2023 was 3.7%; Ontario CPI in 2023 was 3.8%**

	2002-2023 timeframe			2023 growth
	Avg growth	Min	Max	
Canada GDP-IPI FDD	2.2%	1.0%	6.3%	3.7%
Ontario CPI	2.2%	0.4%	6.8%	3.8%

- **Both GDP-IPI FDD and CPI have been approved by regulators in North America**
- **However, using an economy-wide measure requires an input price differential and a TFP differential for the X-factor:**
  - IPD is the difference between rates of change in input prices for the overall economy and the industry
  - TFP differential is the difference between rates of change in the industry TFP study and TFP for the overall economy



Pros

1. **Simplicity**
   - ✓ Single economy-wide measure is simple to understand



Cons

1. **Requires an input price differential and a TFP differential**
   - ✓ Adjustment in TFP trends (X-factor) can be controversial
2. **Direct cost trends in economy are less relevant to industry being regulated**

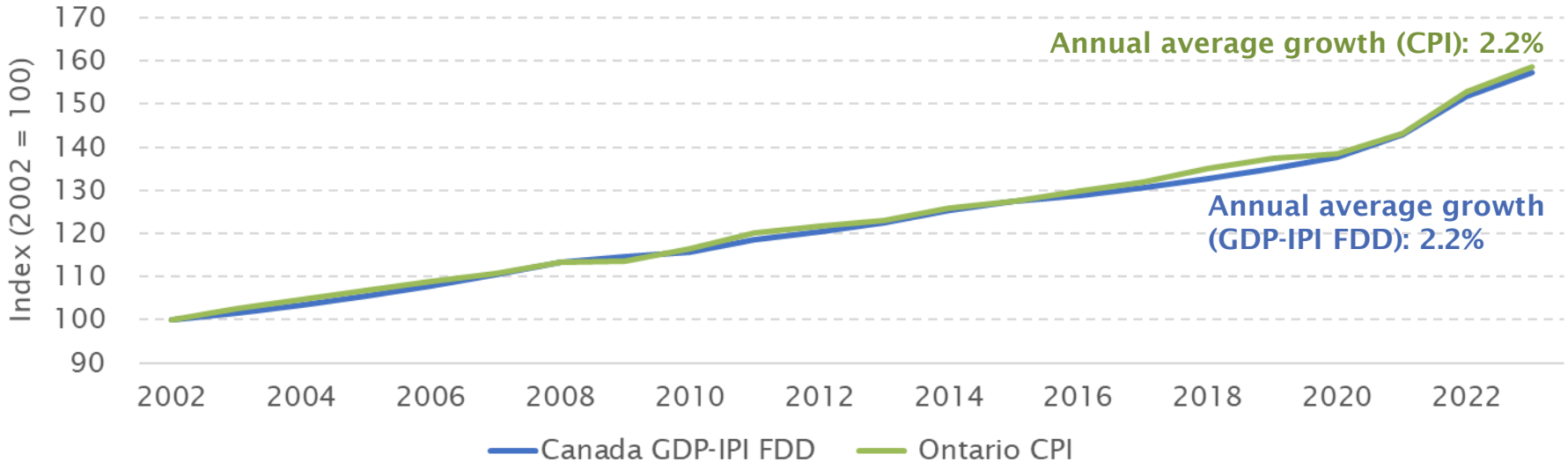
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Ontario CPI and Canada GDP-IPI FDD are economy-wide inflation indices that measure trends in costs of goods and services

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- **StatCan's CPI and GDP-IPI FDD are economy-wide inflation measures**
  - Both indices reflect changes in prices paid by Canadian consumers
- **Utilizing an economy-wide inflation measure requires an input price differential adjustment in TFP trends (X-factor)**
- **CPI and GDP-IPI FDD have similar growth rates over the longer term**
  - Both Ontario CPI and Canada GDP-IPI FDD average growth for 2002-2023 was 2.2%

Criteria	CPI	GDP-IPI FDD
1. Relevance to utility costs	X	X
2. Exogeneity	✓	✓
3. Source reliability	✓	✓
4. Data availability	✓	✓
5. Precedence and simplicity	X	X
6. Index stability	✓	✓



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3 Analysis of potential options

Option 1: Economy-wide inflation index

Option 2: Current composite input price index

Use of AWE and GDP-IPI FDD indices in a 2-factor composite has precedent, is generally relevant to OPG's business, and is easy to understand and apply in an I-X formula

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- **Updated I-factor using the AWE and GDP-IPI FDD composite index in 2023 is 3.6%**

I = 15.3%(AWE) + 9.3%(GDP-IPI FDD) + 75.4%(GDP-IPI FDD)

	2002-2023 timeframe			2023 growth
	Avg growth	Min	Max	
Current composite I-factor	2.3%	1.0%	5.7%	3.6%



Pros

1. Precedence and simplicity
- ✓ Approved by OEB for both electricity distribution and hydroelectric generation
- ✓ Generally accepted by ratepayers
- ✓ Uses publicly available data
- ✓ Easy to calculate and understand

2. Relevance to utility costs
- ✓ Relevance to OPG's unit cost pressures is best achieved with a composite input price index
- ✓ Represents the basic categories of inputs (labour, non-labour)

3. Index stability
4. Exogeneity
5. Source reliability



Cons

1. **Does not specifically represent the capital-related costs and non-labour O&M costs of the hydroelectric generating industry**

2. **GDP-IPI FDD proxies OPG's non-labour O&M (non-capital) and capital costs – but in GDP-IPI FDD, the non-capital to capital weighting is not specific to the hydroelectric industry (it is for all industries)**

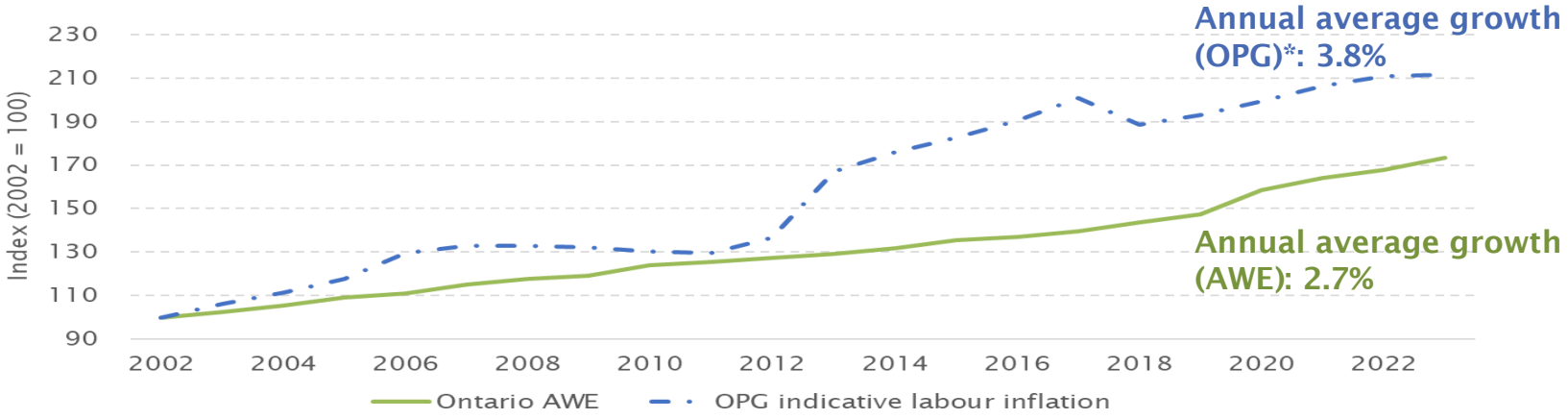
AWE index for Ontario industrial aggregate continues to be a reliable and stable measure of labour cost inflation in the province

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- **StatCan's AWE index for Ontario industrial aggregate shows the average financial return from paid employment**
  - Industrial aggregate includes all industries (as well as utilities), which ensures relevance and exogeneity criteria
  - StatCan has not changed AWE methodology for many years (last change was in 2001) – demonstrates reliability and availability
- **Multiple regulators have approved the use of AWE for a labour price sub index (OEB, BCUC)**

Criteria	AWE
1. Relevance to utility costs	?
2. Exogeneity	✓
3. Source reliability	✓
4. Data availability	✓
5. Precedence and simplicity	✓
6. Index stability	✓

- **Average AWE growth for 2002-2023 was 2.7%, compared to OPG's indicative labour cost growth of 3.8% over the same timeframe**
  - Therefore, using AWE is conservative from the perspective of rate impact and will implicitly create an additional efficiency incentive for OPG

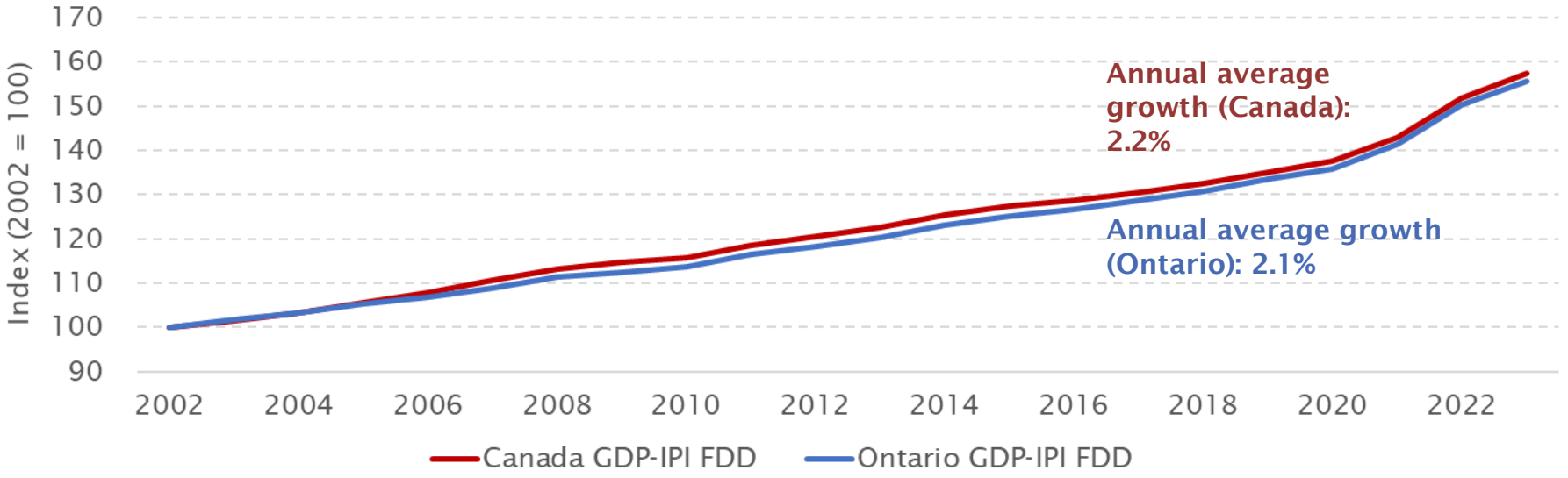


** OPG indicative labour inflation is calculated from data provided by OPG (plant labour cost divided by the number of full-time employees)*

Canadian GDP-IPI FDD measures the price changes of the domestic economy's final goods and services

- **StatCan's GDP-IPI FDD measures broad economy growth**
  - Though an output-based measure, it is a good proxy for non-labour costs, which represent different contract services and procurement of various materials and equipment
  - Broad coverage gives the index stability; average growth for 2002-2023 was 2.2%
- **Ontario and Canada GDP-IPI FDD are very similar, but Ontario data is less frequently updated; as such, OEB has preferred use of Canada GDP-IPI FDD**

Criteria	GDP-IPI FDD
1. Relevance to utility costs	?
2. Exogeneity	✓
3. Source reliability	✓
4. Data availability	✓
5. Precedence and simplicity	✓
6. Index stability	✓



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3 **Analysis of potential options**

Option 1: Economy-wide inflation index

Option 2: Current composite input price index

Option 3: More complex composite input price index

LEI considered a more complex composite input price index, which would consist of sub-indices that are further tailored to OPG's input costs

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- **LEI evaluated options to add a more tailored sub-index for capital and non-labour O&M (materials/services) to the composite index**
  - In the current composite, GDP-IPI FDD is used as a proxy for these two categories of inputs

$$I = \alpha\,(Labour\ inflation) + \beta\,(Non-labour\ inflation) + \delta\,(Capital\ inflation)$$

$$where\ \alpha, \beta, and\ \delta\ represent\ weights$$

Different sets of weights are used for OPG, electric distribution, electric transmission, and gas

- **Although LEI assessed several options for an alternative capital sub-index, there is limited precedent for use of more complex composite indices**
  - Alternative capital sub-indices evaluated by LEI:
    - Canada IPPI as a proxy for capital-related costs (industrial price trends), but not a comprehensive measure of capital
    - Handy Whitman has an index focused on capital-related cost trends in hydroelectric generation in the US
    - LEI estimate of the implied rental price of capital for the hydroelectric industry
  - The alternative capital sub-indices are typically too narrow to cover all of OPG's non-labour inputs; furthermore, the trends are relatively similar to GDP-IPI FDD, so alternative indices may not be adding incremental informational value

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Capital-specific indices may be more relevant to key capital components of the hydroelectric generation business than GDP-IPI FDD, but they tend to be more volatile, sensitive to economic cycles

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- **Capital-specific indices create volatility and can generate a negative I-factor in some years because they account for the majority weight in the I-factor**

I = 15.3%(AWE) + 9.3%(GDP-IPI FDD) + 75.4%(IPPI or HWI or LEI estimate)

Option	Capital sub-index alternatives	2002-2023 timeframe			2022-2023 growth
		Average	YOY min	YOY max	
Composite incorporating a capital specific sub-index	Canada IPPI	2.9%	-0.3%	17.3%	1.6%
	Handy Whitman	3.6%	0.6%	10.9%	4.7%
	LEI estimate of implied rental price of capital	3.2%	-1.5%	10.3%	4.6%
I-factor (using Canada IPPI)		2.8%	0.0%	14.7%	2.0%
I-factor (using HWI)		3.3%	0.7%	9.9%	4.4%
I-factor (using LEI estimate of implied rental price)		3.0%	-0.8%	9.5%	4.3%

Pros

1. Relevance to utility costs and generators

Cons

1. Sensitive to economic cycles/data
- Year-on-year trends can vary significantly, which could lead to volatile rates
- In 1GIRM, OEB expressed concerns with volatility of the capital input measure and refrained from using it again

2. Alternative capital indices do not represent all large hydroelectric generator costs, except for HWI
- However, HWI lacks transparency and methodological clarity, and is only available for purchase

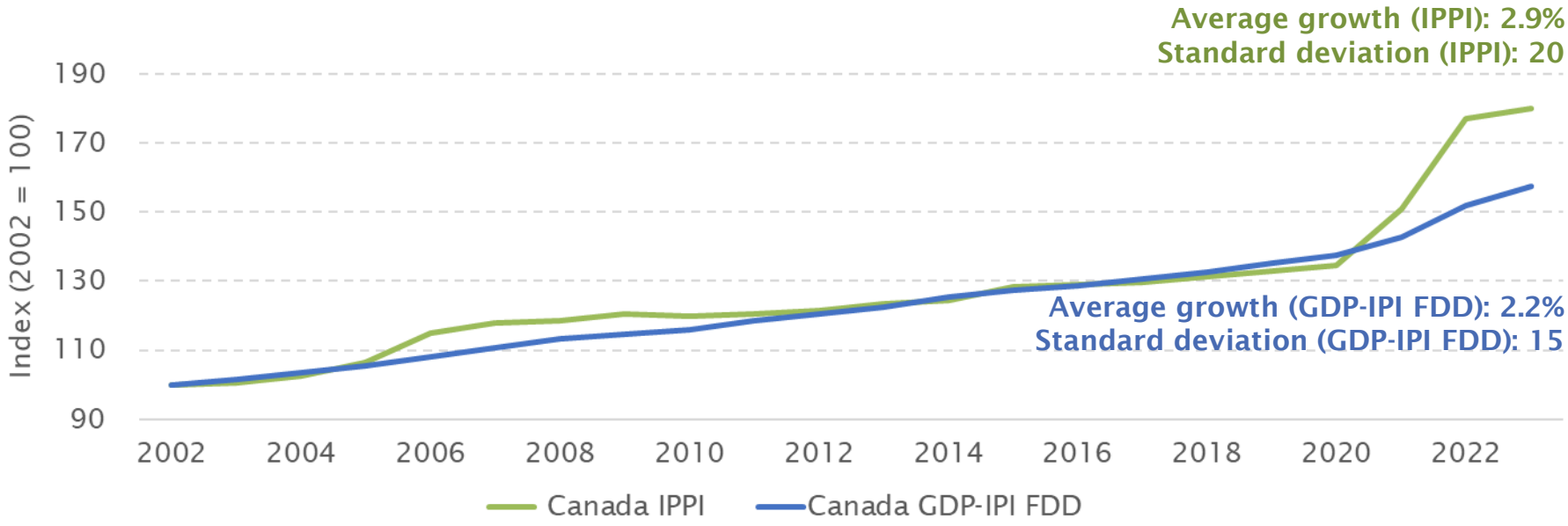
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Canada IPPI is relevant to some utility costs, but exhibits volatility

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- StatCan's IPPI measures changes in selling prices received by producers of various electrical equipment, appliances, and components
- Costs are relevant to a broader manufacturing sector, but not specifically representative of hydroelectric generator costs
- Average IPPI growth for 2002-2023 was 2.9%, with a steep increase in 2021 and 2022

Criteria	IPPI
1. Relevance to utility costs	?
2. Exogeneity	✓
3. Source reliability	✓
4. Data availability	✓
5. Precedence and simplicity	?*
6. Index stability	X



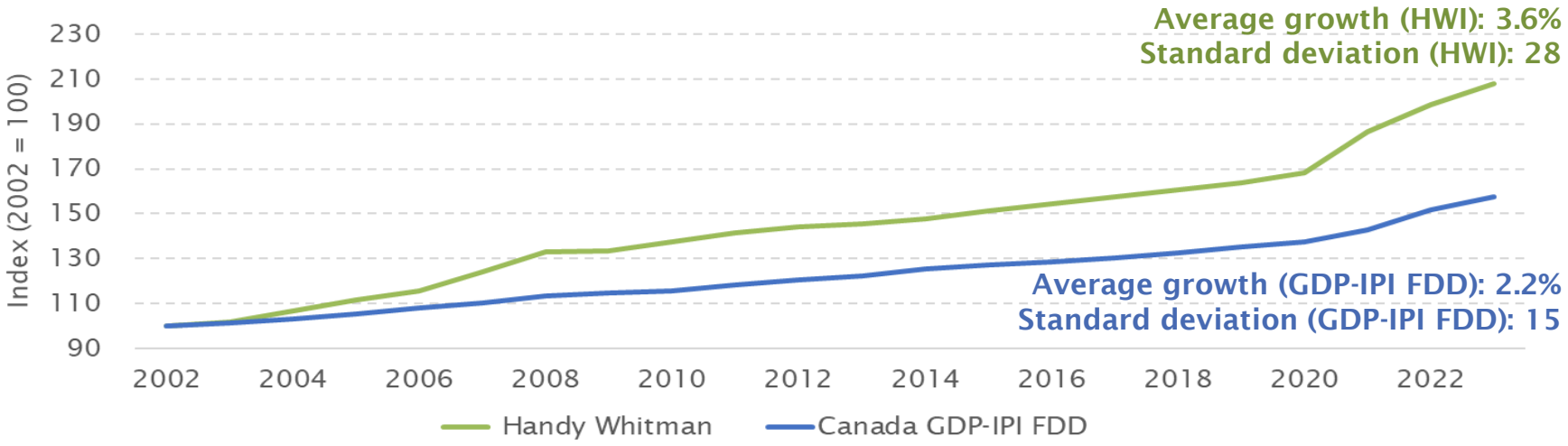
** IPPI was previously used in 1GIRM for materials and previously approved by the BCUC for FortisBC*

Handy Whitman Index measures changes in various utility construction costs, but requires a paid subscription for access

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- **HWI calculates the cost trends for different types of utility construction, with separate indices published for the electric, gas, and water industries**
  - HWI has an index focused specifically on capital-related cost trends in hydroelectric generation
- **Costs are representative of hydroelectric generator costs, but data is not publicly availably**
  - Paid subscription published by Whitman, Requardt and Associates ("WRA")
- **Annual average HWI growth for 2002-2023 was 3.6%**
  - Much higher than Canada GDP-IPI FDD average growth of 2.2%

Criteria	HWI
1. Relevance to utility costs	✓
2. Exogeneity	✓
3. Source reliability	✓
4. Data availability	X
5. Precedence and simplicity	X
6. Index stability	X



For the monetary TFP study, LEI created an implied rental price of capital for the hydroelectric industry that could hypothetically be used as a capital input price index within the I-factor

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- **In 1GIRM, the capital portion of the Input Price Index mechanism was calculated based on a user-cost of capital approach**

$$PK_t = (r_t + d)CAP_t$$

where…

r = 10-year Canada Long Bond yield
d = expected long-term inflation
CAP = StatCan Price Index for Electric Utility Distribution Systems Construction

Sample calculation of capital price index for utility "j"						
Year	10yr bond yield	Depreciation	CAP	P_K	P_K (1999=1.0)	% chg
1999	5.5%	5.39%	123.0	0.133947	1	2.0%
2000	5.9%	5.39%	124.6	0.140673	1.05	5.0%
2001	6.15%	5.39%	125.0	0.14425	1.077	2.6%

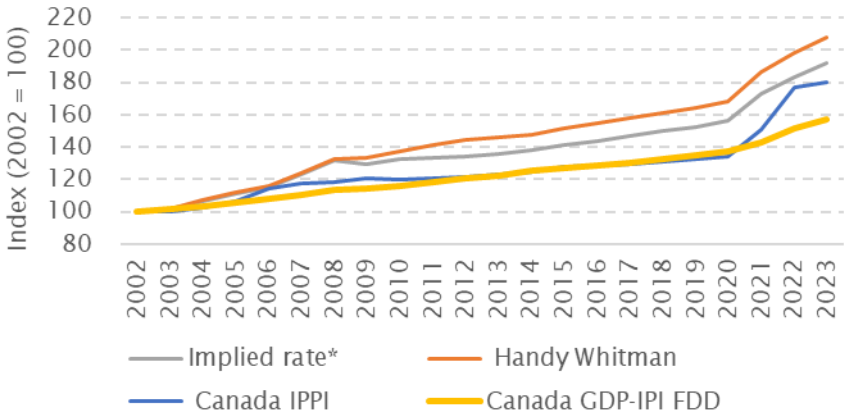
- **LEI's estimated implicit rental price formula reflects trends in cost of capital**
  - Based on an equilibrium relationship between the price an investor is willing to pay for an asset and the after-tax expected value of services that the asset will provide over the asset's lifetime
  - It has a few advantages over the approach used in 1GIRM: it incorporates average service life of the assets, uses a combination of equity and debt (instead of debt only), and has precedent (used in many TFP studies)

Estimated implied rental price of capital*

$$P_{k,t} = \left(\frac{1-uz}{1-u}\right)(r-i)\left[1-\left(\frac{1+i}{1+r}\right)^{s}\right]^{-1} P_{A,t\text{-}1}$$

where…

u = corporate profits tax rate
r = cost of capital, estimated using the OPG WACC from 2002-2023
i = expected Canadian long-term inflation
s = average service life
z = present value of the depreciation deduction on new investment
$P_{A,t\text{-}1}$ = construction cost deflator based on HWI



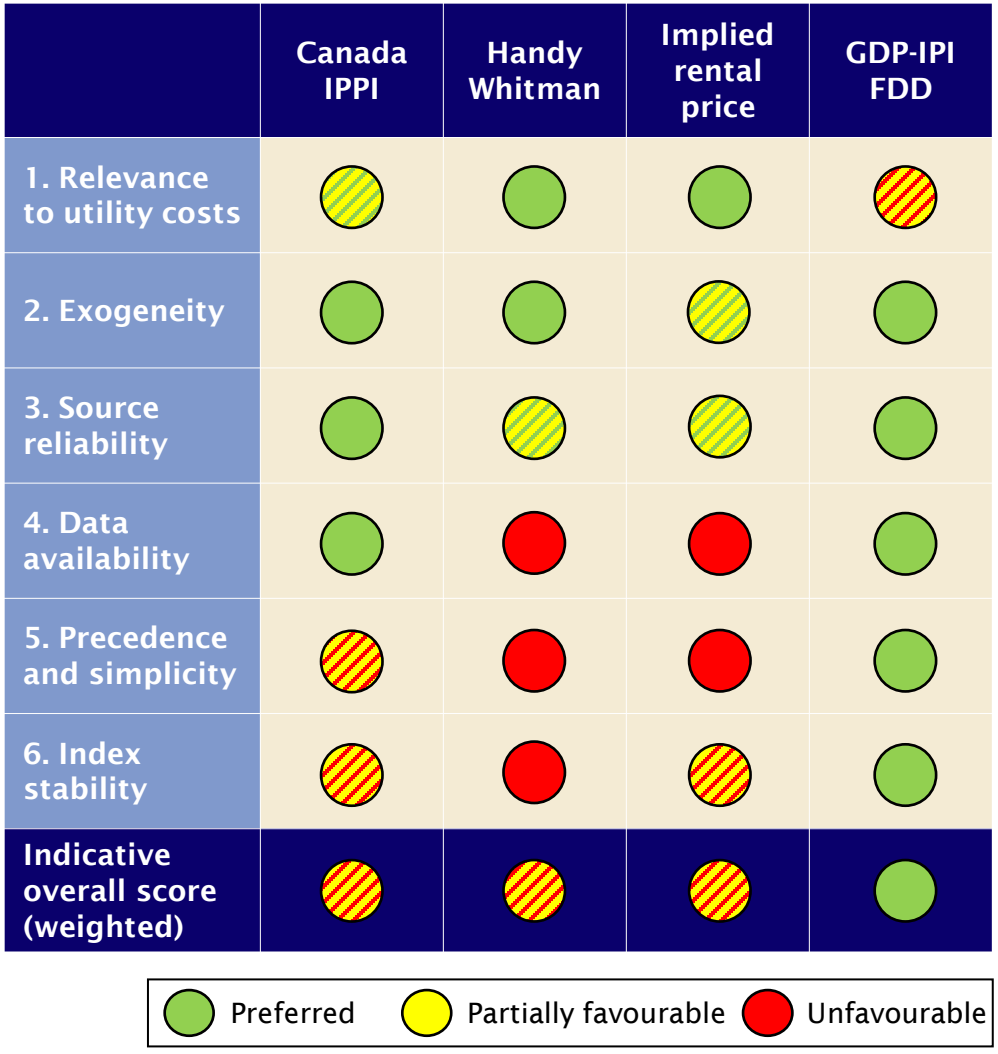
** Using Canadian-long term inflation, calculated using nominal 10-year GC benchmark bond yields and Canadian real return bond ("RRB") yields*

Volatility, data availability, and complexity are barriers to implementation of a capital-specific input price sub-index

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- **Although a tailored capital sub-index such as StatCan's IPPI, Handy Whitman, or LEI's implied rental price estimate would be relevant to certain capital costs, historical data shows that these indices are sensitive to economic cycles**
  - Year-on-year trends can vary significantly, which could lead to more extreme rate changes
- **Indices may not cover all hydroelectric capital costs**
- **OEB has previously raised similar issues in its decision for RRFE**

  "Board and many stakeholders were concerned that the resulting numbers generated do not appear reasonable and result in unacceptable volatility"



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1	Introduction to I-factor and recap of OEB 2017 Decision
2	Criteria to design an I-factor
3	Analysis of potential options
4	**LEI's recommendation**

The current two-factor composite index (Option 2) remains the most appropriate I-factor methodology due to relevance, precedence, simplicity, and stability

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- **Option 1:** Using an economy-wide measure requires an input price differential and a TFP differential for the X-factor
- **Option 2:** The current AWE and GDP-IPI FDD composite input price index has precedence, it is generally relevant to OPG's regulated hydroelectric business, is easy to understand/apply, and exhibits stability over time
- **Option 3:** Adding a more capital-specific sub-index for the capital portion of the composite index formula can be risky, as capital input indices tend to exhibit more volatility (sensitivity to economic cycles), are more complex, and are not always readily available (such as the HWI, which requires a paid subscription for access)
  - Option 3 uses either IPPI, HWI, or implied rental price for the capital portion only

Options	Index	2023 I-factor
1) Economy-wide inflation index	Canada GDP-IPI FDD	3.7%
	Ontario CPI	3.8%
2) Current composite input price index	**AWE and GDP-IPI FDD**	**3.6%**
3) More complex composite input price index	Canada IPPI	2.0%
	Handy Whitman	4.4%
	LEI estimate of implied rental price of capital	4.3%

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LEI recommends the continued use of Ontario AWE for labour costs and Canada GDP-IPI FDD for capital and non-labour costs, with updated weighting based on the current TFP Study

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- **After analyzing different indices and options for input price composites, LEI recommends continuing use of the AWE/GDP-IPI FDD composite index**
- **The composite input price index is a weighted sum of capital, labour, and non-labour (material) indices**
  - Weighting comes from average industry cost shares used in the TFP study
- **The composite input price index has been stable over time, with an average historical growth of 2.3% (2002-2023)**
  - Analysis of different time periods within the 2002-2023 timeframe confirms the stability of the I-factor
  - However, both AWE and GDP-IPI FDD have demonstrated higher growth in the past 4 years

Timeframe	Inflation growth
Avg 2002-2023	2.3%
Min (2015-2016)	1.0%
Max (2021-2022)	5.7%
Recent (2022-2023)	**3.6%**

The AWE and GDP-IPI-FDD composite:

- ✓ has precedent
- ✓ is generally relevant to OPG's business
- ✓ is easy to understand/apply
- ✓ is stable over time

- **Other recently approved I-factors are in line with the 3.6% composite index value for 2023, despite different weights, and in some cases, use of different indices**
  - OEB: 2025 I-factor was set at 3.6% for electricity distributors and 3.7% for electricity transmitters
  - OEB Enbridge 2025: 3.61%
  - AUC PBR3 2024: 4.02%
  - BCUC FortisBC 2025: 4.288%

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EMPIRICAL ANALYSIS OF TOTAL FACTOR PRODUCTIVITY TRENDS IN THE NORTH AMERICAN HYDROELECTRIC GENERATION INDUSTRY

Prepared for

Ontario Power Generation

by



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Content as of June 2025

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1 Executive summary

London Economics International LLC ("LEI") was engaged by Ontario Power Generation ("OPG") to perform a total factor productivity ("TFP") study of the hydroelectric generation industry for purposes of calibrating the base productivity component of the X factor in the second-generation hydroelectric payment amounts ("HPA") application before the Ontario Energy Board ("OEB"). This report presents and discusses the results of LEI's hydroelectric generation industry TFP analysis covering the 2002-2023 timeframe.

In February 2016, LEI prepared a similar hydroelectric generation industry TFP study in conjunction with OPG's first-generation HPA application (referred to herein as the "LEI 2016 TFP Study"). In performing the current analysis, LEI used the same analytical techniques but with an extended timeframe (updated to include 2015-2023 data) and a larger group of peers from the North American hydroelectric generation industry. Furthermore, for the current analysis, LEI calculated the TFP growth trends using both a physical ***and*** a monetary approach to measuring capital input quantities.

For the industry consisting of 20 US peers plus OPG, using data from 2002-2023, LEI calculated the TFP growth rate to be -0.40% per annum using a physical measure of capital input and the 'trend regression' method of estimating the growth rate. Using a monetary approach to measuring capital input, and a slightly reduced peer group (16 US peers plus OPG) due to data availability issues, LEI calculated a TFP growth rate of -1.01% per annum under the 'trend regression' method. For comparison purposes, if LEI had used the same reduced peer group for the physical approach as for the monetary approach, the TFP growth rate would have been -0.61% (see Figure 1). LEI notes that while OPG is included within the industry sample, removing OPG from the peer group does not materially change the TFP results.[1]

Figure 1. Average annual TFP growth rate over 2002-2023 period using the trend regression method

Measure of capital input	Peer group	TFP growth rate
Physical	20 US peers plus OPG	-0.40%
Monetary	16 US peers plus OPG	-1.01%
Physical	16 US peers plus OPG	-0.61%

The LEI 2016 TFP Study had reported a -1.18% industry average TFP growth rate for the 2002-2014 timeframe, using the physical approach for measuring capital input and the 'trend

[1] LEI continues to believe that the regulated company (such as OPG) should be part of the industry that is being examined for purposes of setting an X factor for that company, unless it can be shown that the regulated company's productivity trends are truly outside the norm and distort the industry trend. However, removing OPG from the peer group in LEI's analysis does not change the TFP growth rate results materially. The average annual TFP growth rate for the industry using a physical measure of capital input and the 'trend regression' method of estimating the growth rate, even without OPG, remains negative at -0.87% for the physical method and -0.40% for the monetary method over the 2002 through 2023 time period.

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regression' method of calculating the average annual growth rate. The updated TFP results are slightly less negative than the previous TFP study, mostly reflecting a recent trend observed among the US peers of higher generation output in the additional years of the study (2015-2023), as well as the impact from the inclusion of new large peers such as the Western Area Power Administration ("WAPA"). In other words, the higher generation output for a comparable quantity of inputs results in higher productivity (i.e., slightly less negative productivity growth).

The main takeaway from these results – across the various technical approaches used in the TFP calculation – is that outputs have generally been growing more slowly than inputs, resulting in a negative TFP trend for the industry. As explained further throughout this report, negative TFP results can be expected for mature hydroelectric generation businesses, because of fixed production capabilities and rising asset maintenance costs over time.

1.1 What is TFP?

Total factor productivity measures the total quantity of a firm's outputs relative to the quantity of inputs it employs. TFP must cover all material inputs to production and core outputs of a firm. TFP focuses on physical quantities of inputs and outputs, not specific costs,[2] and as employed here, measures the year-on-year changes in overall productivity for the firm and its peers. It is important to note that the TFP analysis undertaken in this study focuses on changes over time in productivity at the industry level and is not intended to measure productivity levels for individual firms at any specific point in time. An industry TFP study by definition will ***not*** focus solely on the regulated firm, but rather measure the trend in productivity for the industry. The TFP study, by its nature, relies on historical data and therefore is reporting on historical growth rates or trends in productivity for the industry. A growth rate reflecting multiple years (at least 10 years, but preferably longer if good quality data is available)[3] is the primary result reported in an industry TFP study for purposes of calibrating the base productivity component of the X factor under a formulaic-based regime.

1.2 What data was used for the TFP study?

Selecting the appropriate inputs and outputs is a key part of a TFP study. Based on best practices of estimating TFP for electric generation companies, and after considering issues related to data availability, LEI defined the TFP study output as generation in megawatt hours ("MWh"), which the OEB agreed was the most appropriate output measure in its December 28, 2017 Order on OPG's application for the first-generation HPA (EB-2016-0152) (referred to herein as the "2017 Decision").[4]

LEI considered inputs that reflected the total costs of operation: quantities of capital employed, as well as quantities of labour and materials based on operations and maintenance ("O&M")

[2] While costs are not the focus of a TFP study, they are still needed to form input weights; this is described further in Section 5.3.3.

[3] And there has not been a major change in the underlying production process.

[4] OEB. *Decision and Order EB-2016-0152 - Ontario Power Generation Inc. Application for payment amounts for the period from January 1, 2017 to December 31, 2021.* December 28, 2017.

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costs.[5] There are two methods for estimating capital input quantities: a physical approach and a monetary approach. The physical approach uses physical indicators such as installed capacity in megawatts ("MW") to produce an estimate that reflects the quantity of capital employed to generate electricity, while the monetary method estimates capital input quantity through depreciated asset values in constant dollar terms.[6] LEI employed both the physical approach and the monetary approach for measuring capital inputs in this TFP study, in order to reflect OEB's guidance around capital input quantity measurement from the 2017 Decision.

In respect of data selection and gathering, primary data sources include Federal Energy Regulatory Commission ("FERC") Form 1, Energy Information Administration ("EIA"), Statistics Canada ("StatCan"), United States Bureau of Economic Analysis ("US BEA"), United States Bureau of Labor Statistics ("US BLS"), the Organisation for Economic Co-operation and Development ("OECD"),[7] company public reports, as well as data provided directly by OPG.

The industry TFP study using the physical capital input quantity approach includes 21 firms in total: OPG, 16 US investor-owned firms that file FERC Form 1 ("FF1") data, and 4 US federal and municipal operators. This industry sample includes 5 additional peers as compared to the LEI 2016 TFP Study. Data for this study covers a 22-year period from 2002 through 2023.

In response to OEB's guidance in the 2017 Decision to seek to include Canadian peers in the industry sample, LEI expended significant effort to try to obtain data from Canadian hydroelectric generators. However, due to data availability limitations (see Section 4.3 for further details), LEI was not able to include Canadian firms other than OPG in the study.

For the industry TFP study using the monetary approach, LEI relied on a reduced peer group (the 16 US peers that file FERC Form 1 data plus OPG) due to data availability issues. LEI had to drop the 4 US federal and municipal operators as these entities are not regulated by FERC and thus are not required to submit FERC Form 1 data, and the data required to calculate the capital input quantity for these peers was not available at the level of granularity needed to be included in the monetary TFP analysis.

Despite these data availability constraints, LEI believes the TFP analysis presented in this study is robust and reliable for its intended purpose of calibrating the base productivity component of the X factor.

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[5] Quantities of O&M were calculated using annual O&M costs measured in dollars and deflated by an appropriate index in order to isolate productivity trends. See Section 4 for details on how this data was used and Section 5 for details on the deflation index.

[6] Depreciated asset values under the monetary method do suffer from certain analytical subjectivity. See Section 3.2.4 for a discussion on the issues with selecting the appropriate depreciation profile.

[7] Data in US dollars was converted to Canadian dollars using the purchasing power parity ("PPP") for gross domestic product ("GDP") between the US and Canada, as estimated by the OECD. Please refer to Section 4.5 for further information on PPP adjustments.

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1.3 How should the results of the TFP study be used for rate setting?

The industry TFP in this study measures the average annual change in overall productivity for the hydroelectric generation industry over a period of 22 years. It is the industry growth rate that is most relevant in calibrating the base productivity component of the X factor for setting regulated prices for a future period. Using an industry-wide TFP rate rather than an individual firm's TFP rate supports the incentive-based goals of the incentive ratemaking ("IR") regime, while minimizing the risks associated with firm-specific volatility. Using industry-level data over a long-term period also improves quantitative reliability of the resulting TFP measure and reduces the influence of data anomalies or timing of investment decisions by individual firms.

An industry TFP study reports historical productivity growth rates; therefore, in the context of relying on that data for forward rate setting purposes, care must be applied to ensure that going forward business conditions are similar to those that prevailed historically. LEI expects that going forward, operating conditions for hydroelectric generation assets will remain generally stable – the operating profiles of these long-lived assets are pre-conceived in the design before they are constructed. Although there are incremental improvements in materials and equipment, they are not fundamentally changing how water flow creates electricity. In this way, hydroelectric generation is a mature and well-established industry that is not anticipated to undergo material changes to productivity in the foreseeable future.[8] Over time, we do expect that climate change implications (on hydrology) may impact production. We also see societal concerns heightening around safety and environmental and ecological factors. Empirically, these more recent factors have not had a major impact on measured TFP. However, with time and additional data, that may change.

Based on the theoretical principles for application of a formula-based IR price cap, LEI recommends that the results of this industry TFP study be used to inform the setting of the X factor under the I-X regime for OPG's next generation of IR for the prescribed hydroelectric assets. LEI's TFP study calculates a negative TFP growth rate for the hydroelectric generation industry. The presence of a negative TFP trend is consistent with expectations given sector conditions. Even under relatively stable operating conditions, rising O&M costs (driven by maintenance of aging assets and compliance with increasingly stringent regulatory requirements) can outpace any gains in output, leading to negative productivity growth.

1.4 Roadmap for the report

This report is structured as follows: Section 2 introduces the background to this study. Section 3 presents an overview of the various methods of measuring total factor productivity growth, and explains why the TFP index method was selected for this study. Section 4 goes over the data gathering process for the peers that made up the industry group used in the TFP study. Section 5 presents the inputs and modeling techniques leveraged in LEI's TFP studies using both the

[8] Finley-Brook, Mary. "Hydropower." In *Achieving Sustainability: Visions, Principles, and Practices*, edited by Debra Rowe, 464-69. Vol. 1. Gale, 2014.

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physical and the monetary approaches to measuring capital input. Section 6 presents the results of the analyses. Section 7 provides concluding remarks.

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2 Background

Under *Ontario Regulation 53/05* pursuant to Section 78.1 of the *Ontario Energy Board Act*, 1998, the OEB's mandate includes setting payments for OPG's prescribed assets (nuclear and hydroelectric).[9]

OPG retained LEI in late 2013 to perform an industry productivity study for OPG's prescribed hydroelectric assets. LEI prepared a TFP report for OPG covering the 2002-2014 timeframe on February 19, 2016, which was filed alongside OPG's application for hydroelectric payment amounts (EB-2016-0152). In the 2017 Decision, the OEB did not object to LEI's use of an index-based TFP methodology and accepted OPG's proposed X factor of 0%.[10] The OEB further agreed that LEI's use of generation, measured in MWh, as a measure of hydroelectric companies' output, was the most appropriate output measure.[11] However, the OEB requested that future studies consider alternative capital input quantity measures, as well as additional peers.

With regards to the sample of industry peers used in the study, the OEB noted that the study did not include Canadian generators other than OPG. For this study, LEI expended significant effort reaching out directly to Canadian peers to try to obtain data, as there is no publicly available centralized source of data for Canadian hydroelectric companies.[12] In an effort to expand the industry sample further, LEI also contacted several non-FERC jurisdictional US entities such as the New York Power Authority ("NYPA"), Southwestern Power Administration ("SWPA"), Tennessee Valley Authority ("TVA"), United States Bureau of Reclamation, and others. However, all Canadian hydroelectric companies and some of the larger non-FERC jurisdictional US entities that LEI contacted with data requests were not able or willing to provide their data in the disaggregated format and over the timeframe that LEI required for the TFP study. Nevertheless, LEI was able to add several US-based peers to the industry sample for a total of 21 firms (including OPG).

Regarding the capital input quantity measure, the OEB recognized that LEI's physical approach in the LEI 2016 TFP Study had not been relied upon previously by the OEB. Specifically, the OEB was unsure whether the physical approach reflected incremental investment and appropriate levels of depreciation of the assets over time.[13] Although it is true that the physical approach does

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[9] OEB. *Ontario Energy Board Act, 1998.* <http://www.e-laws.gov.on.ca/html/statutes/english/elaws_statutes_98o15_e.htm>

[10] "*OEB finds that a base productivity factor of 0%, as proposed by OPG, is appropriate for OPG's hydroelectric IRM plan.*" Source: OEB. *Decision and Order EB-2016-0152 - Ontario Power Generation Inc. Application for payment amounts for the period from January 1, 2017 to December 31, 2021.* December 28, 2017. P. 128.

[11] "*The OEB agrees with LEI that generation (MWh) is the most appropriate measure of output, as it is generation produced, and not capacity, which is the basis for revenues to recover capital and operating costs.*" Source: OEB. *Decision and Order EB-2016-0152 - Ontario Power Generation Inc. Application for payment amounts for the period from January 1, 2017 to December 31, 2021.* December 28, 2017. P. 126.

[12] See Section 4.3 for further details, including the list of Canadian peers that LEI reached out to.

[13] The OEB commented that "*LEI's physical method… assumes no depreciation until the end of life.*" Source: OEB. *Decision and Order EB-2016-0152 - Ontario Power Generation Inc. Application for payment amounts for the period from January 1, 2017 to December 31, 2021.* December 28, 2017. P. 127.

not reflect the common accounting definition of depreciation expense, it *does* consider physical deterioration as reflected in the annual measurement of the Maximum Continuous Rating ("MCR") of each plant.[14] Furthermore, incremental capital investment is implicitly captured in the MCR measure, as maintaining or enhancing installed capacity over time requires ongoing investment. Indeed, LEI has observed that some of the hydroelectric plants included in the industry sample for the TFP study increased their MCR over time. If the generator did not undertake such investments to sustain the productive capacity of its hydroelectric assets, a decline in MCR would be observed. Nonetheless, for this study, in order to be responsive to the OEB's 2017 Decision and reflect a variety of approaches, LEI performed the TFP calculations using both the physical and monetary approaches. In Section 3.2.4, LEI also details how the physical approach takes into account physical depreciation and new investment in capital inputs, rectifying some potential misconceptions about the physical method and further explaining how functional or physical depreciation is measured.

This study continues to use well-conceived and commonly accepted methods for calculating the TFP trend, while also responding to the considerations that the OEB raised in the 2017 Decision. As such, LEI believes that it provides a robust analytical foundation for setting the next generation of IR for OPG's prescribed hydroelectric assets.

[14] MCR means the gross or net maximum electrical output (in megawatts) which a generation unit or generating station is currently capable of producing continuously. This may include seasonal effects or other "long-term" deratings. Source: Independent Electricity System Operator ("IESO"). *Market Rules. Chapter 11. Definitions.* January 30, 2020.

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3 Methodological considerations for an industry TFP study

In performing the TFP analysis, LEI reviewed existing literature on the subject and carefully considered various analytical methodologies, indexing techniques, input and output measures, and appropriate study timeframes, before selecting the most appropriate methodology for the hydroelectric industry.[15]

3.1 What is productivity?

Productivity is the ratio of the quantity of outputs produced by a firm, to the quantity of inputs used by the firm. Productivity growth is a trend variable, based on the year-on-year change in the productivity ratio, or mathematically, the rate of growth in the quantity of outputs minus the rate of growth in the quantity of inputs. For purposes of incentive ratemaking, and specifically in the design of price caps and revenue caps, regulators are typically interested in *changes in productivity over time*. Historical productivity growth can inform regulators and the regulated utility on the productivity change that should be expected from the industry going forward, which then guides the choice of an explicit productivity growth target or X factor under an I-X price cap or revenue cap.

Although there are multiple methods for measuring productivity, in a practical sense, most TFP study methods for regulatory purposes focus on recording changes in output quantities relative to changes in input quantities over time. Common drivers of increased productivity growth include technological progress,[16] economies of scale,[17] and economies of scope.[18] When attempting to measure total factor productivity trends, one would seek to capture the inputs and outputs comprehensively.[19]

Finally, it is noteworthy that by their nature, TFP studies are inherently backward looking, reporting historical growth rates. The theoretical premise is that long-term trends would be expected to continue going forward, so long as the industry is in a reasonably steady state,

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[15] The LEI 2016 TFP Study included a summary of the existing economic literature on TFP measurement in the electricity sector. To LEI's knowledge, no new empirical TFP studies specific to electricity generation have been published in the regulatory context since then. See Appendix C for further details.

[16] Technological progress refers to improvements in the methods of producing goods and services, which allow for increased output without increasing the amount of inputs. Source: Malcolm Pemberton and Nicholas Rau. 2015. *Mathematics for economists: An introductory textbook*, 4th Edition.

[17] Economies of scale refer to the cost advantages that a firm can exploit by expanding its scale of production, leading to a fall in average costs. Source: Pindyck, Robert S., and Daniel L. Rubinfeld. *Microeconomics*, 9th Edition.

[18] Economies of scope exist when it is less costly to produce two or more goods together than it is to produce each one separately. Source: Pindyck, Robert S., and Daniel L. Rubinfeld. *Microeconomics*, 9th Edition.

[19] It is possible to measure varying categories of productivity – for example, for assessing labour productivity, one would look at the ratio that represents the quantity of labour relative to the quantity of output. Labour productivity is a partial measure of productivity, also known as partial factor productivity ("PFP"). The distinction between the TFP measure and the PFP measures therefore lies in the number of inputs analyzed – single factor productivity measures (or PFPs) relate output to a single input, whereas TFP considers output relative to all inputs. PFP measures can be misleading if considered in isolation. Source: OECD. *Measuring Productivity: Measurement of aggregate and industry-level productivity growth.* 2001.

meaning that there are no disruptive technological innovations that would change the production process, or the level of output created from a similar quantity of inputs. The hydroelectric generation industry qualifies for steady state characterization. Although there are incremental improvements in materials and equipment, they are not fundamentally changing how water flow creates electricity. Over time, we do expect that climate change implications (on hydrology) may impact production. We also see societal concerns heightening around safety and environmental and ecological factors. Empirically, these more recent factors have not had a major impact on measured TFP. However, with time and additional data, that may change. Notwithstanding the relative stability of the industry, it is important to note that hydroelectric operators experience capital investment cycles, which may not necessarily occur at the same time for all generation operators. Those capital investment cycles may therefore impact the firm's own TFP more so than the industry TFP.

3.2 Overview of TFP methods

The following section provides an overview of the various methods for performing a TFP study. TFP methods can be broadly categorized into deterministic methodologies, which "calculate" TFP, and econometric methodologies, which provide a "statistical estimate" of TFP. Figure 2 summarizes some of the methods LEI considered – the index method, data envelopment analysis ("DEA"), and stochastic frontier analysis ("SFA"). Appendix C provides more information about the different methods for measuring productivity that LEI considered for the analysis.

LEI chose to use a TFP index method. The index method is a deterministic methodology. Regulators, including the OEB, have typically favored this method because it is straightforward to understand. TFP index methods measure the ratio of all outputs to all inputs, where input and output indexes are constructed using quantities of outputs and inputs (and where there are multiple inputs, prices are used to weight and combine the various input quantities).[20] Traditionally, TFP indexing can be used to compare rates of change of productivity but not absolute levels (although more complicated multilateral index methods do also enable levels comparison).

The benefits of TFP indexing are that it is a relatively simple, easy to communicate, and robust technique that requires significantly fewer observations than the other measuring techniques, and thus is often used for regulatory proceedings. TFP indexing is also more transparent when dealing with outliers, unlike DEA and econometric techniques. It is important to note that the TFP index method, because it is a numerical technique as opposed to a statistical technique, does not give a forecast error measure. Therefore, interpreting differences in index values requires qualitative considerations. Finally, LEI notes that the OEB and other regulators are familiar with the index approach,[21] and in the Renewed Regulatory Framework ("RRF") proceedings, the OEB

[20] Deterministic methodologies "calculate" TFP values and therefore cannot measure performance or productivity relative to an efficiency frontier. In effect, non-frontier methods assume that the industry is always efficient in its use of existing technology, at each moment in time. Non-frontier methods do not provide separate estimates of technical change and efficiency change.

[21] The TFP index method has also been used in previous industry productivity studies before the OEB and is a preferred method among practitioners for I-X regimes – see Appendix C for further details.

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stated its preference to continue to rely on productivity factors that were determined using the index-based approach.[22]

Figure 2. Empirical techniques for estimating TFP

	Non-Frontier technique	Frontier techniques	
Parameters	**Index Method**	**Data Envelopment Analysis ("DEA")**	**Stochastic Frontier Analysis ("SFA")**
Description	Index number measures the ratio of all outputs (weighted by revenue shares) to all inputs (weighted by cost shares)	Linear programming technique which identifies best practice within a sample by fitting a frontier over the top of the data points and measures relative inefficiencies	Same as DEA but following econometric methods to estimate the efficiency frontier
Data needs	Quantity and price data on inputs and outputs for 2 or more firms	Quantity data on inputs and outputs for a sample of firms; price data required to get information on allocative efficiency	Quantity data on inputs and outputs for a sample of firms; price data required to get information on allocative efficiency
Advantages	Relatively simple and robust technique. Can incorporate many inputs and outputs with few observations	Can decompose cost efficiency into component parts, breaking down allocative and technical efficiencies. Can easily handle multiple outputs	Can decompose cost efficiency into component parts, breaking down allocative and technical efficiencies. Accounts for "data noise" (data errors, omitted variables, etc.) and allows for the use of standard statistic tests
Drawbacks	Does not allow for identification of various factors of TFP change such as technical efficiency, scale efficiency, etc.	Requires a large dataset. Sensitive to the way outputs and inputs specified. Can be difficult to explain in a regulatory setting	Requires large sample size for robust estimates. Requires specification of production or cost function. Can be difficult to explain in a regulatory setting

Source: Coelli et al. *A Primer on Efficiency Measurement for Utilities and Transport Regulators.* World Bank Institute. February 2003.

3.2.1 Selecting an indexing technique

The TFP index methodology requires selection of an indexing technique in order to calculate TFP growth rates.[23] Similar to the LEI 2016 TFP Study, LEI selected the Fisher Ideal index as theoretically superior to other index methods,[24] meeting all four criteria that an index number method needs to meet: constant quantities test, constant basket test, proportional increase in

[22] OEB. *Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*. Issued November 21, 2013, corrected December 4, 2013.

[23] LEI's review and analysis of indexing techniques can be found in Appendix C.

[24] Other index methods include the Laspeyres index, Paasche index, and Törnqvist index.

outputs test, and time reversal test.[25, 26] The Fisher Ideal index is also theoretically superior as it is the geometric mean of two other indices, the Laspeyres index and the Paasche index. By taking the geometric mean, the Fisher Ideal index calculation offsets the upward bias of the base-period-focused Laspeyres index and the downward bias of the current-period-focused Paasche index (see Appendix C for further details).

The Fisher Ideal index can be formed as a chained or an unchained index. In line with the LEI 2016 TFP Study, LEI used the chained Fisher Ideal index.[27]

3.2.2 Defining output(s)

Selecting the appropriate inputs and outputs represents a key part of a TFP study. Hydroelectric generation assets provide a multi-dimensional service: the primary output or product is energy. But some hydroelectric generation units also provide ancillary services, firm capacity, support for the overall power system, and water management for flood control and recreational use.

Based on LEI's prior review of productivity studies on generation, and similar to the methodology used in the LEI 2016 TFP Study, LEI selected generation as the metric for measuring output.[28] In its 2017 Decision, the OEB agreed that generation is the most appropriate output measure.[29] Generation is an appropriate indicator because it is the essential output being produced by every power generator, and also encapsulates availability of the resource. Additionally, generation directly captures the productivity benefits of common runner upgrade projects for hydroelectric generation assets, where the incremental investment typically increases annual energy output. Furthermore, generation data is readily available and is generally measured consistently across power plants and firms. Based on this, LEI concluded that annual generation measured in MWh continues to be the most appropriate output measure for a TFP study of this nature.

LEI recognizes that the generation output metric is partially dependent on weather, and in turn, hydrology, and other factors impacting system operations. However, the longer-term nature (22 years) of the TFP study compensates for the year-on-year variability in annual generation, and

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[25] Diewert and Nakamura. *Concepts and Measures of Productivity: An Introduction.* 2005.

[26] Although other experts may choose to use other index methods, that decision should not materially impact the conclusions in a long term TFP study such as the one performed by LEI.

[27] The chained Fisher Ideal index overcomes a common "index number problem" found in the formulation of other indices. Instead of using one base observation for the whole period, the chained methodology calculates the Fisher Ideal index for each period using the previous period's observation as the base, linking these different calculations together to form an index number series, which uses the most representative weights possible for each observation. LEI's review and analysis of the chained Fisher Ideal index and other indexing techniques can be found in Appendix C.

[28] More information on the academic and regulatory TFP studies reviewed by LEI can be found in Appendix C.

[29] "*The OEB agrees with LEI that generation (MWh) is the most appropriate measure of output, as it is generation produced, and not capacity, which is the basis for revenues to recover capital and operating costs.*" Source: OEB. *Decision and Order EB-2016-0152 - Ontario Power Generation Inc. Application for payment amounts for the period from January 1, 2017 to December 31, 2021.* December 28, 2017. P. 126.

therefore LEI believes variability in annual hydrology should not be an obstacle for this TFP study.

3.2.3 Dual approaches to calculation of the capital input quantities

For the hydroelectric business, one of the important inputs to production is capital. There are two possible methods for estimating capital input quantities: a physical method and a monetary method. The physical method uses a physical indicator of the capital deployed at each power plant – namely the capacity rating of the hydroelectric facility (in MW), whereas the monetary method uses depreciated asset values in constant dollar terms.

The perceived advantage of the monetary method is that it combines the different types of equipment used at each power plant, because the value of the firm's capital equipment is aggregated using monetary value as the unifying element. While not explicitly studied in this TFP study, the monetary method would also allow the use of different depreciation profiles. The monetary method also directly accounts for the magnitude of investments made to capital assets from time to time.

It is also important to understand the complications and potential shortcomings of the monetary method. The most significant weakness is that the financial data on capital spending and retirements is typically not reported on a disaggregated basis for each category of asset in real dollars and does not go back to the initial year of investment. Hydroelectric companies normally only report the change in asset value (gross book value) for their entire stock of assets. The values of the new assets are added (or subtracted, when assets are retired) based on original cost at the time of the asset acquisition, and therefore the gross book value mixes assets acquired over different time periods, which makes it challenging to ascertain a "real dollar" value for comparison across time. Furthermore, the historically incurred capital cost does not get adjusted over time for the condition of the asset. Thus, one must apply exogenous assumptions regarding the physical deterioration (or physical depreciation) of the capital stock over time under the monetary approach, which is further discussed in Section 3.2.4.

Another weakness is that the monetary approach requires data going back many years, which is difficult to gather for many industries, but is especially difficult in the generation sector of the electric power industry, given the changes in corporate structures and ownership as a result of deregulation and restructuring. For this TFP study, the monetary approach could only be applied to a reduced peer group relative to the physical approach, demonstrating the practical constraints of the monetary approach when capital-related data is not available for the requisite timeframe.[30]

[30] For most of hydroelectric generation assets, there is lack of recorded public data to the date of original construction (which we refer to as "date of origination"), which means that we are forced to accept a starting point that does not go back to the date of origination, which we refer to as the "benchmark year" for the capital data series. Since the capital quantity estimate will not be exact, it is preferable to have capital input data as far back as possible so that the vintages of additions and retirements can be more accurately accounted for. Based on industry practice, a significant number of years of data is typically required (above and beyond the TFP study timeframe) in order to reasonably estimate the capital input quantities. LEI went back to 1994 in assembling the appropriate capital data series for the monetary approach (going back further than this is not

In contrast, the physical method is relatively straightforward to apply if the service provided by the capital inputs of a business can be adequately measured using physical proxies. In the case of hydroelectric generation, it is relatively straightforward to measure the productive capability or service that the capital assets provide. If a particular capital asset deteriorates, then the rated capacity of the plant will decline. On the other hand, capital improvements can increase the rated capacity of a hydroelectric plant. In industries such as electric and gas distribution, there is not a singular technical measure that describes the capital assets of a given company over time, because the ability of these utilities to provide a service to consumers (delivery of electricity or natural gas) depends on multiple and distinct classes of assets.[31] In contrast, a universal measure of productive capacity of a hydroelectric power plant is available. The MCR or total capacity of a power plant universally describes how the various components of a power plant work together to be able to produce energy. MCR values can change from year to year based on upgrades and/or physical deterioration of the assets. For generation-related TFP studies, it is common to use a measure of capacity like MCR to represent the capital input of the business.[32] This is a readily available metric that is comparably measured across companies and over time.

3.2.4 How does the TFP study capture physical depreciation of assets?

In order to approximate the capital input quantity under the monetary approach, one needs to employ a depreciation assumption. The depreciation assumption in a TFP study is not tied to the accounting or tax rules; while some assumptions around financial depreciation are necessary for cost recovery purposes, a TFP study is only concerned with physical deterioration of the asset and its ability to function and produce a product or service. [33] Physical depreciation and financial depreciation patterns can vary.[34] Indeed, the physical ability of a power plant to produce energy, which is used to measure productivity in the case of our TFP study, may remain relatively constant until it is retired.

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practical and would have meant losing data coverage for some peers, which would have reduced the scope and representativeness of the TFP study).

[31] For example, substations, poles, and wires for electric utilities, or compressor stations and pipelines for gas utilities.

[32] More information on the academic and regulatory TFP studies reviewed by LEI can be found in Appendix C.

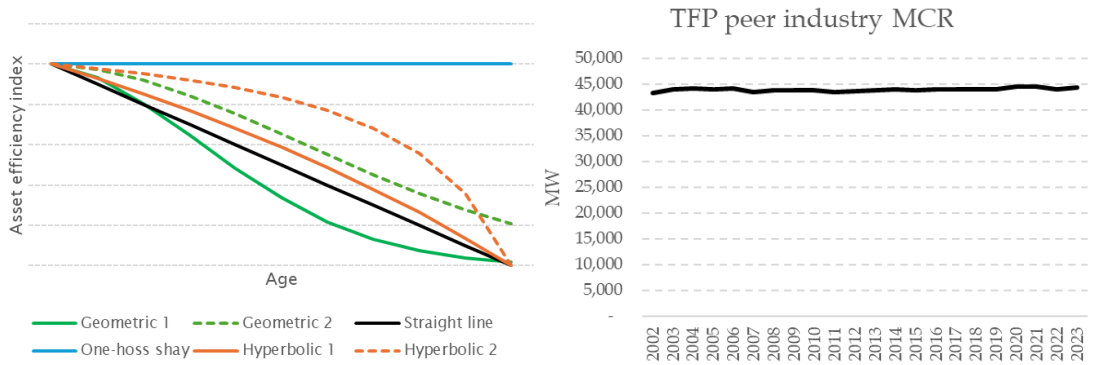
[33] Physical depreciation does not have to equal financial depreciation. It has been shown in prior academic research that one can match different economic depreciation profiles and still achieve the principles of effective ratemaking. *See* Schmalensee, R. "An expository note on depreciation and profitability under rate-of-return regulation." Journal of Regulatory Economics. 1989.

[34] The validity of separate treatment of economic and physical depreciation is based on the concept of financial capital maintenance ("FCM"), which refers to an investor maintaining the value of their financial capital at stake. Under the FCM proposition, the investor can expect to get their capital back (through depreciation expense) and earn their expected rate of return. In the context of incentive ratemaking, "prices" (i.e., the value of electric generation being sold) are set so that the present value of expected efficient costs over the relevant time horizon is equal to the present value of expected revenues. The discount rate for calculating the present values should be the expected (allowed) weighted average cost of capital. The starting price is configured to ensure that for the starting year, expected revenues equal expected costs including an appropriate return on capital and an allowance for economic depreciation. It then follows that the focus thereafter is on the cost and productivity (or TFP) indexation factors, where productivity should reflect the physical ability of a resource to generate an output (i.e., physical depreciation, not financial depreciation).

With the physical method, any physical deterioration (the physical ability of a resource to generate output) will be captured by the MCR value,[35] whereas the monetary approach requires application of physical deterioration assumptions, as the financial data used under the monetary approach will not capture physical deterioration over time. Hydroelectric generation assets tend to have long lives and produce a relatively constant flow of services over their useful lives (provided they are properly maintained).[36] Furthermore, physical deterioration is generally very limited in hydroelectric plants as the majority of the capital equipment deployed is not electrical or mechanical, but structural. Structures account for the largest share of capital assets and can provide service for over 100 years, based on technical depreciation studies that LEI reviewed for hydroelectric generation fleets (see Section 5 for additional information). As a result, many "common" financial depreciation profiles are unlikely to properly reflect the true physical depreciation profile of these assets. Geometric decay or straight-line depreciation profiles are examples of such common, yet erroneous, depreciation profiles. When studying the TFP trends for an economy (across multiple industries), statistical agencies have often relied on geometric decay or hyperbolic depreciation profiles; however these agencies typically perform their studies across large economic sectors, and therefore it is more appropriate for a hyperbolic profile to apply in such a context, as the capital deployed in one sector may have a shorter life than the capital deployed in another sector, and a hyperbolic profile is a proxy for this service-life variation. This is not as applicable to the hydroelectric generation industry.

Based on the technical evidence, physical deterioration of hydroelectric assets is more aligned with a one hoss shay ("OHS") depreciation profile given the assets' long productive lives, as illustrated in Figure 3 below.

Figure 3. Efficiency profiles for alternative depreciation profiles compared to MCR



Note: As demonstrated in the charts above, MCR is fairly constant, similar to the OHS depreciation profile.

[35] Generators provide the IESO, at least annually, with declared MCR values at five ambient temperatures for units sensitive to temperature. The IESO uses this data to determine seasonal net MW values based on monthly normal weather forecasts. For temperature-insensitive units, generators submit monthly MCRs that reflect expected deratings from external factors such as cooling water temperature. Source: IESO. *Market Manual 2.8: Reliability Assessments Information Requirements*. 2020.

[36] "*Whereas most generation technologies have a life of 20–30 years, a well-maintained hydropower facility can operate for more than 100 years.*" Source: World Bank. *Operation & Maintenance Strategies for Hydropower – Handbook for Practitioners and Decision Makers*. 2020.

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3.2.5 Measuring TFP growth rates

The key finding of an industry TFP study is a numerical estimate of the TFP growth rate over the study period timeframe. The common approach, referred to as the "average growth" method, calculates the year-on-year changes in the TFP index and then takes the average of the resulting growth rates over the course of the study period.[37] As further outlined in Figure 4 below, a mathematical equivalent can be calculated by: (i) taking the natural logarithm of the ratio of the last TFP index value divided by the first TFP index value, and then (ii) dividing the resulting value by the number of annual year-on-year observations between the start and end year.

Figure 4. Calculating average TFP growth for a study period of 2002-2023

$$\text{Average industry TFP growth} = \ln\left(\frac{\text{2023 industry TFP index}}{\text{2002 industry TFP index}}\right) / 21$$

Note: The number of year-over-year observations can be calculated as the number of years for which data is collected as part of the TFP study period minus one. For this study, a study period of 2002-2023 has 22 years of data and therefore has 21 data points for the change in TFP year-over-year.

However, if there is a bias in the starting and ending values (in the case of this study, 2002 and 2023), this may be a problem. For example, if the 2023 TFP index value is unusually high, the calculated average growth rate over the 2002-2023 timeframe would be overstated, even if underlying long-term productivity improvements were more modest. Conversely, an unusually low 2023 TFP index value would understate longer-term trends if using the "average growth" method. For this reason, LEI prefers using the 'trend regression' method, which is a regression-based method that estimates the linear trend of the TFP index values over the study period timeframe. As outlined in Figure 5 below, this method is calculated by carrying out a linear regression of the natural logarithm of the TFP index values against the number of years of the study period (starting from 0) and a constant term. The estimated slope of this regression is the average TFP growth rate.[38]

Figure 5. Trend regression of TFP growth for a study period of 2002-2023

$$\textbf{Regress: } \ln(\text{industry TFP index}) = \beta * T + \alpha$$

Where:
β = trend growth rate for the industry TFP index over the study period
T = time in years $(0, \ldots, 21)$
α = constant term

"Average growth" is the more common method of measuring the study-period TFP growth rate and has been used in previous studies presented before the OEB.[39] The preference of this method can be attributed to the fact that it calculates the actual growth rate of the TFP index values over

[37] Economic Insights. *Total Factor Productivity Index Specification Issues*. December 7, 2009.

[38] Ibid.

[39] *See for example* PEG. *Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board.* November 2013.

the course of the study period and is easy to understand. However, in certain instances, the average growth method can be misleading, most notably when a series exhibits volatility at its endpoints. Because the average growth method tracks the exact growth from start to end, if the endpoints of a series are outliers with respect to the trend, then the average method may not give a very good estimate of the underlying TFP trend. In instances where a series is volatile at its endpoints, the 'trend regression' method is likely to give a better estimate of the underlying TFP growth trend, in that it reduces the weight attached to the first and last years of the study period. The trend regression method has been used to calculate trend growth rates in New Zealand and Australia.[40]

While each method has its own set of strengths and weaknesses, LEI presents the results for both methods in this report. However, LEI believes that the trend regression method offers a better representation of the TFP trend in the case of hydroelectric TFP because of the magnitude of variability in annual generation. Annual generation is influenced by hydrology, which can create bias around specific endpoint values, especially if those annual values happen to fall at the start (2002-2003) or at the end (2022-2023) of the TFP study timeframe, distorting the overall long-term growth trends being reported.[41]

3.3 Appropriate length of TFP study

The main purpose of conducting a TFP study of this nature is to establish industry trends, which are innately long term. Logically, the best method for establishing a trend is to look at multiple years of data and performance. Multiple years of data limits bias that can be caused by numerical outliers or one-off events that affect performance in any single year. Therefore, a productivity trend should cover a period that extends through a sufficiently long timeframe, to limit exposure to year-on-year productivity changes as well as one-off circumstances with respect to factors like weather, consumption, lumpy capital spending, and fluctuations in labour.

This is especially true for hydroelectric generation businesses, which go through business cycles related to the long lifetime of the assets, and where productivity is also heavily dependent on shorter term exogenous factors such as hydrology, which can lead to high year-on-year variability in output. The use of a long-term data series helps smooth out anomalies associated with one-off circumstances and compensates for year-on-year variability that is observed in the data.

Conversely, if the range of data is too long, the estimated trends may be biased and not representative of current and prospective dynamics, and thus irrelevant for informing future ratemaking. Therefore, the time period should ideally incorporate recent data that captures the industry drivers, while eliminating earlier time periods that are no longer relevant.

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[40] For an example of a TFP study using the trend regression method see: Economic Insights. *Electricity Distribution Industry Productivity Analysis: 1996–2008*. September 1, 2009.

[41] Note that the presentation of both methods only refers to the final TFP growth estimate value. In all other instances, such as when estimating quantity sub-index growth rates, both methods follow the exact same process, until the final step of calculating the TFP growth rate over the study period timeframe.

Given best practices for TFP analysis, the steady-state nature of the hydroelectric generation industry, and the variability of hydrology conditions that can affect output (generation) and thus the measure of productivity, LEI believes that the longest timeframe allowed by the availability of data (2002-2023) is appropriate for this study. For OPG, 2002 is also the year that the Ontario competitive electricity market opened, a significant event impacting OPG's business environment. US electricity markets also underwent reforms and restructuring phases in the late 1990s and early 2000s. Therefore, given data availability and quality, LEI believes that the 22-year timeframe supported by reliable data is appropriate, as it is long enough to limit the impact of one-off factors, while also being short enough to reflect more recent business circumstances in the industry, which are likely to be driving productivity in the future.

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4 Data for the TFP study

LEI researched and gathered data from several sources in order to create a peer group representative of the North American hydroelectric industry. Ultimately, LEI was able to assemble a peer group of 20 US hydroelectric companies (investor-owned utilities or "IOUs", municipal, and federal agencies) in addition to OPG. Unfortunately, despite extensive efforts spanning more than 50 hours of primary research, written and telephonic outreach, LEI was unable to obtain the necessary time series data from Canadian peers specific to their hydroelectric generation fleet. Nonetheless, LEI believes the data used for this TFP analysis is robust and reliable for the intended purpose of calibrating the base productivity component of the X factor.

4.1 Peer selection

Ideally, a hydroelectric industry TFP study would include a large set of peers that are similar in terms of location, capacity, and asset allocation. In the LEI 2016 TFP Study, LEI included medium to large hydroelectric generators. For this study, LEI relied on the same base group of peers but was able to add peers and expand the size of the industry sample used in the study. LEI focused its data research on the United States and Canada due primarily to data availability. As outlined below, LEI considered a total of 38 hydroelectric peers across North America, including 30 in the US and 8 in Canada (including OPG). However, issues with data availability meant that 17 of these peers could not be included in the final industry peer group. In particular, except for OPG, no other Canadian firm could be included in the study. In the US, all major utilities are required to submit comprehensive financial and operating reports to the FERC under FERC Form 1, which is then made publicly available.[42] In contrast, no such data bank exists in Canada, and therefore the financial data required for the TFP study from Canadian peers could not be obtained either through public resources or, despite LEI's exhaustive outreach efforts, directly from the individual utilities. Still, LEI believes that a set of 20 US peers plus OPG is sufficient for developing a robust TFP trend for purposes of IR.[43]

4.1.1 Peer selection criteria

When selecting peers to construct an industry group, LEI used a multi-dimensional set of criteria, which focused on comparability across peer hydroelectric operations, while keeping in mind issues related to data availability. In the LEI 2016 TFP Study, LEI looked for firms that have a hydroelectric fleet with a total capacity between 500-1,000 MW (medium size) or more than 1,000

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[42] FERC Form 1 is a regulatory requirement for major electric utilities, designed to collect financial and operational information on utilities subject to FERC jurisdiction. Major utilities are defined as: having *"one million megawatt hours or more; 100 megawatt hours of annual sales for resale; 500 megawatt hours of annual power exchange delivered; or 500 megawatt hours of annual wheeling for others (deliveries plus losses)."* FERC Form 1 filings can be found here: <http://www.ferc.gov/docs-filing/forms/form-1/data.asp>

[43] LEI notes that there is OEB precedent for relying on US data when necessary. See for example Pacific Economic Group's report, "Price Cap Index Design for Ontario's Natural Gas Utilities" (March 2007), which was undertaken under OEB directive. This study used US TFP results to establish TFP growth targets for two Canadian gas utilities (Enbridge Gas Distribution Inc. and Union Gas Limited). Report filed under OEB case number EB-2006-0209, available online at: <http://www.ontarioenergyboard.ca/documents/cases/EB-2006-0209/TFP_study_20070330.pdf>

MW (large size). For this TFP study, to maximize the number of peers included in the industry sample, LEI incorporated additional peers with smaller fleet sizes (<500 MW). Additionally, LEI included peers if they owned more than one plant, and ideally the average age of a peer's hydro fleet would be around the average age of OPG's prescribed hydro fleet. Practical considerations relating to the availability of reliable data over the entire study timeframe also played an important part in peer selection.[44]

In addition to meeting the above criteria, peers needed to have data available for the hydroelectric portion of their operations, in order to ensure consistency of data. Inputs and outputs, and therefore productivity, would be completely different for thermal generation, for example. For peers which exclusively operated hydro facilities, this was straightforward. However, several potential peers were excluded from the study because there was no clear division in reported O&M data between the hydro and non-hydro components of their operations.[45] Peers needed to have annual data on O&M costs (measured in dollars), installed capacity (measured in MW), and net generation (measured in MWh) for the 2002 through 2023 timeframe. Revenue data was also collected when available, but was estimated when necessary (see Section 4.4 for more detail); revenue data was needed to estimate the capital input share under the physical approach. In addition, for the monetary approach, LEI required annual data on capital investments and retirements for the hydroelectric facilities going back to 1994, as discussed further in Section 4.1.3.

LEI considered multiple reputable primary sources for data including FERC Form 1, EIA, StatCan, US BEA, US BLS, Independent System Operator ("ISO") price data, the North American Electric Reliability Corporation ("NERC"), and company public reports and websites. Although LEI relied mainly on primary sources, data was also sourced and cross checked against third party commercial databases.[46] LEI also derived labour and non-labour O&M shares from the confidential Electric Utility Cost Group ("EUCG") Hydroelectric Productivity Committee ("HPC") database for the TFP study.[47]

OPG also provided LEI with operating and financial data for its regulated hydroelectric fleet for this TFP study, including MCR values, capital investment and retirement data, net generation, O&M (excluding water rental charges/Gross Revenue Charges or "GRC"), and revenue data for

[44] Note that LEI did not consider the ownership structure of the firm, the regulatory regime under which the firm operated, or the type of energy market in which the firm operated (e.g., bilateral energy versus regional transmission organization ("RTO") administered energy market, energy-only versus energy and capacity).

[45] For example, Bonneville Power Administration ("BPA") has a generation portfolio composed 77% of hydro facilities. The company's annual report publishes data on generation, O&M, revenues, and capital, but at a company level only (including non-hydro assets). BPA does not report FERC Form 1 data, where O&M would have been disaggregated for hydroelectric versus other forms of generation.

[46] Including S&P Capital IQ.

[47] While various sources were used to create the dataset used in the final analysis, LEI believes these different sources are comparable because a TFP study is an analysis of trends rather than efficiency levels. Therefore, any potentially unobserved inconsistencies between datasets will not impact results in the same way as they would for a benchmarking study.

the study timeframe. Net generation and O&M figures were provided from January 2002 until December 2023. Data covering 2002-2015 was identical to the LEI 2016 TFP Study.[48]

As discussed previously in Section 3.3, a 22-year timeframe was chosen for the study because it is the longest timeframe allowed by the availability of data, while also being long enough to smooth out anomalies associated with one off circumstances, but also incorporating and reflecting more recent business circumstances in the industry. The start year of 2002 was chosen because it was the first year that full datasets could be constructed across the peer group.[49] As well, the opening of the Ontario competitive market occurred in 2002, which impacted the business environment for OPG; similarly, market restructurings were occurring across parts of the US in the late 1990s and early 2000s. The end year, 2023, was chosen because this represented the latest available information when LEI started gathering data for this study in 2024. Considering issues related to data availability and length requirements of a TFP study, LEI determined a study period timeframe of 2002 through 2023 was reasonable.

4.1.2 Final peer group

Consistent with the above criteria, LEI began the data collection process with a target of 38 industry peers in North America, including 30 in the US and 8 in Canada. These consisted of OPG, 16 private US companies that file FERC Form 1 data, 14 US federal and municipally owned companies, and 7 Canadian hydroelectric generation owners.[50]

However, primarily due to the lack of certain necessary data, 17 of the 38 targeted peers could not be included. The final peer group selected, as summarized in Figure 6 below, includes 21 firms: OPG, 16 US investor-owned firms that file FERC Form 1 data, 2 US federal operators (Western Area Power Administration and Southeastern Power Administration), and 2 US municipal operators (Seattle City Light and Chelan County Public Utility District). The newly included federal and municipal operators have sizeable (>1,000 MW) hydroelectric generation fleets. As further described in the next section, the monetary approach TFP analysis only includes OPG and the 16 US investor-owned firms that file FERC Form 1 data.

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[48] As in the LEI 2016 TFP Study, OPG revenue data for January until April 2002 was not available due to markets opening in May 2002; therefore, revenue amounts had to be imputed. All other revenue data from April 2002 onwards was provided directly by OPG (note revenue provided by OPG solely represents energy market sales of hydroelectric generation, based on actual settlement with the IESO; it does not reflect any variance accounts, regulatory rate true ups, or any other payments such as Surplus Baseload Generation, Hydroelectric Incentive Mechanism or ancillary services). Revenue figures for the missing months (January until April 2002) were estimated by multiplying net generation for each month by the average monthly Hourly Ontario Energy Price ("HOEP") for the same month in 2003-2012. Averaging over multiple years helps to normalize for variations in supply-demand conditions and market prices, reducing the influence of any single year's anomalies. However, LEI notes that using different estimation methods to calculate OPG's 2002 revenue between January and April had little to no effect on the final industry TFP results.

[49] Most peers did not have full datasets available before 2002, including OPG, which had revenue data only available starting mid-2002 after market opening.

[50] BC Hydro, Brookfield Renewable Partners, Hydro-Quebec, Manitoba Hydro, NB Power, Newfoundland & Labrador Hydro, and TransAlta.

Figure 6. List of industry peers included in TFP study

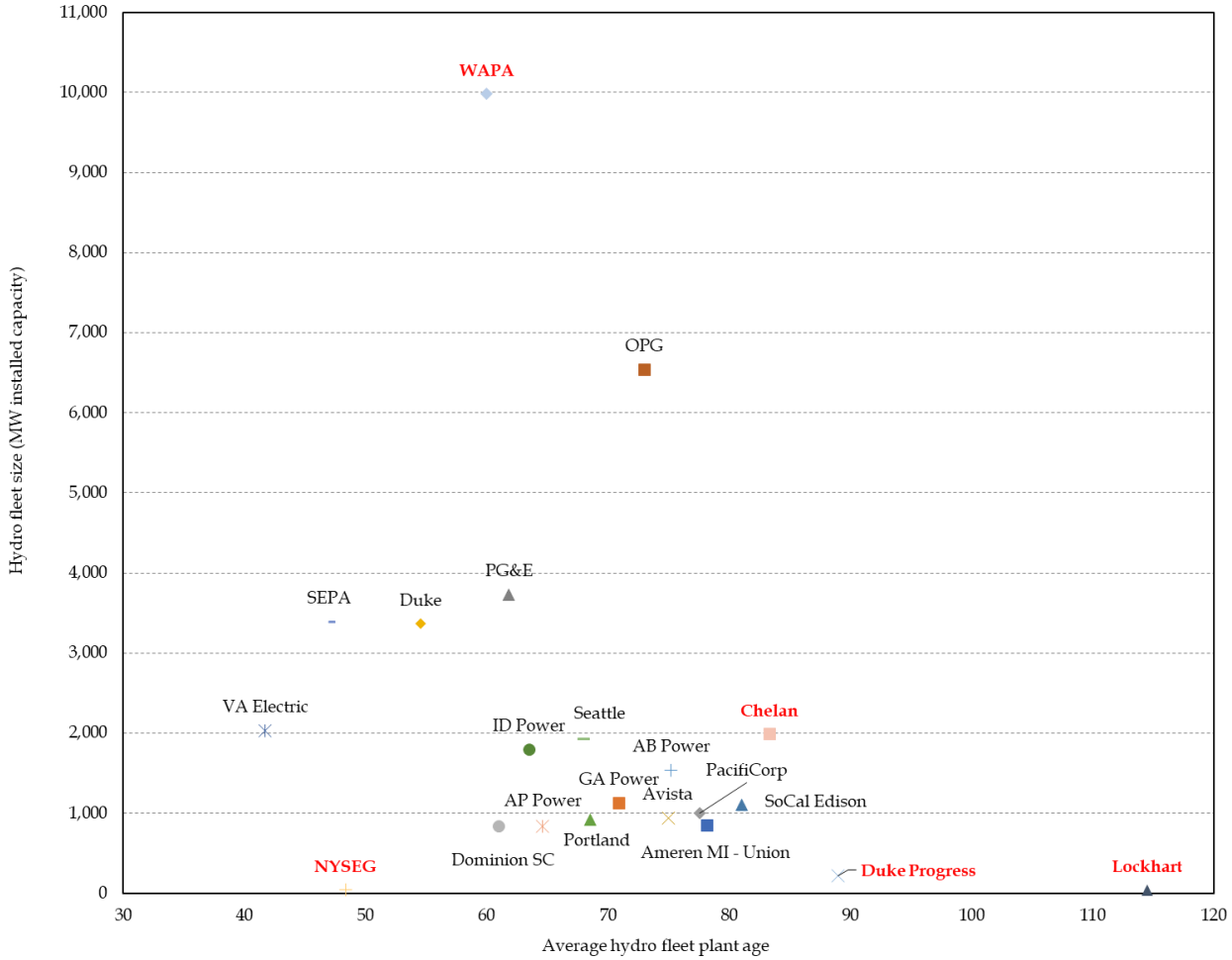
Company	Average age of hydro fleet (2023)	Sum of hydro plants capacity (MW) 2023
Pacific Gas and Electric	62	3,729
Duke Energy Carolinas, LLC	55	3,367
Virginia Electric and Power	42	2,032
Idaho Power Company	63	1,790
Alabama Power	75	1,537
Southern California Edison Company	81	1,106
Georgia Power Company	71	1,128
PacifiCorp	78	1,006
Avista Corporation	75	940
Portland General Electric Company	69	924
Union Electric	78	846
Appalachian Power Company	65	838
Dominion Energy South Carolina	61	838
Duke Energy Progress, LLC	89	217
Lockhart Power Company	115	44
New York State Electric & Gas Corporation	48	47
Ferc Form 1		
Western Area Power Administration	60	10,035
Southeastern Power Administration	47	3,365
Seattle City Light	68	2,014
Chelan County Public Utility District	83	2,037
Federal and Municipal		
OPG	**73**	**6,534**

Source: FF1 dataset, OPG, SEPA, Seattle and Chelan annual reports, data provided directly by companies.
Note: New peers added relative to the LEI 2016 TFP Study are highlighted in light grey in the table above.

Figure 7 charts the peer companies as a function of their hydro fleet size and average age, while Figure 8 illustrates a breakdown of the 4 largest peers in terms of capacity and O&M costs.

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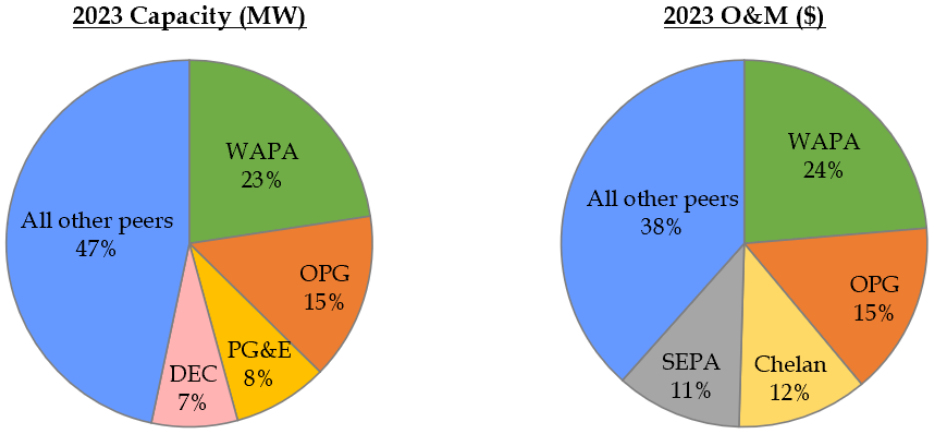
Figure 7. List of peers by capacity and average age of hydro fleet (as of 2023)



Note: New peers added relative to the LEI 2016 TFP Study are indicated in red font in the chart above.

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Figure 8. Breakdown of top 4 firms in industry sample by 2023 capacity (MW) and O&M ($)[51]



Source: FF1 dataset, OPG, WAPA, SEPA, Seattle and Chelan annual reports, data provided directly by companies.

4.1.3 Peer selection for the monetary method

For the TFP analysis using the monetary approach, LEI was not able to find sufficient data related to annual capital investment for the non-FERC regulated hydroelectric companies. The monetary approach to estimating capital input relies on a longer time series than the physical TFP method in order to build a real capital input quantity estimate as accurately as possible. Notably, LEI required annual capital spending (investment) and retirement data going back to 1994.

LEI contacted the non-FERC regulated hydroelectric companies to try and obtain the required data, but it was not readily available. As such, LEI had to drop the 4 federal and municipally owned hydroelectric companies from the industry sample shown previously in Figure 6 on page 26 (specifically, Western Area Power Administration, Southeastern Power Administration, Seattle City Light, and Chelan County Public Utility District) for the monetary approach.

4.2 FERC Form 1 data

As discussed previously in Section 4.1 and as presented in Figure 9 below, LEI identified 16 US peers that submit FERC Form 1 annually. FF1 data is submitted by all major electric utilities and is available for large hydro plants. FERC provides guidelines on data requirements; therefore, data sourced from FF1 can be considered reliable. The use of a single dataset also provides consistency. FF1 data was used for total O&M costs (non-capital input), installed capacity (capital

[51] O&M amounts for US peers were converted from US dollars to Canadian dollars using the average 2002-2023 OECD PPP for GDP, at a rate of 1.20 Canadian dollars per 1 US dollar. See Section 4.5 for further explanation of the conversion process. Furthermore, all O&M values were deflated by their respective indices in order to isolate productivity trends, as described in further detail in Section 5.

input), generation (output), and capital investments and retirements.[52] Where possible, LEI cross-checked FF1 data with other data sources to ensure that the TFP study is using reliable data.

Figure 9. List of FF1 peers including 2023 capacity, O&M (US $), and net generation data

Ferc Form 1 peers	Capacity (MW)	O&M ('000$)	Net Generation (MWh)
Pacific Gas and Electric	3,729	141,091	9,671,209
Duke Energy Carolinas, LLC	3,367	37,264	4,546,626
Virginia Electric and Power	2,032	20,491	2,825,892
Idaho Power Company	1,790	40,942	6,485,260
Alabama Power	1,537	19,897	3,698,090
Southern California Edison Company	1,106	58,426	3,074,548
Georgia Power Company	1,128	18,414	1,634,725
PacifiCorp	1,006	44,128	2,878,452
Avista Corporation	940	13,663	3,024,124
Portland General Electric Company	924	29,677	2,279,018
Union Electric	846	13,292	1,349,232
Appalachian Power Company	838	16,033	1,020,916
Dominion Energy South Carolina	838	9,780	634,548
Duke Energy Progress, LLC	217	5,450	603,521
Lockhart Power Company	44	2,296	109,026
New York State Electric & Gas Corporation	47	2,019	168,122

4.2.1 Consistency between FF1 and OPG data

LEI attempted to maximize data consistency by using the same data source (FERC Form 1) as much as possible. However, there were still some instances where the method of reporting for primary data differed between industry peers. Most notable was the use of operations, maintenance, and administration ("OM&A") costs for OPG versus O&M for all other peers. Data provided by OPG included administrative costs, but FERC Form 1 data does not report administration costs at the hydroelectric business level. Consistent with the LEI 2016 TFP Study, administration costs were found by OPG to be relatively flat historically and were not a sizeable component of the total OM&A, so their inclusion would not measurably impact the long-term average TFP trends.

Other O&M data was confirmed to be consistent between FF1 and OPG. Figure 10 below shows the list of FF1 O&M line items compared to the expenses covered by the OM&A information provided by OPG. Note that the "water for power" line item was removed from FF1 O&M costs for consistency, as OPG's water rental and GRC fees are pass-throughs and therefore do not affect the productivity of OPG's operations.

[52] Consistent with the LEI 2016 TFP Study, LEI performed adjustments for two companies to correct certain data issues or missing data points in FF1 annual filings. Specifically, Duke Energy's 2002 FF1 data was missing, so O&M and generation were interpolated for that year based on 2001 and 2003 values. Alabama Power's generation data was missing for 2004, and therefore also required interpolation.

Figure 10. FF1 O&M line items compared to items included in OPG costs

Line item	Included in OPG total O&M costs (without HTO and Corp)
Operation	
535 Operation supervision and engineering	Yes
536 Water for power	No
537 Hydraulic expenses	Yes
538 Electric expenses	Yes
539 Miscellaneous hydraulic power generation expenses	Yes
540 Rents	Yes
Maintenance	
541 Maintenance supervision and engineering	Yes
542 Maintenance of structures	Yes
543 Maintenance of reservoirs, dams and waterways	Yes
544 Maintenance of electric plant	Yes
545 Maintenance of miscellaneous hydraulic plant	Yes

4.2.2 Federal and municipal peer data

14 federal and municipally owned companies were evaluated for consideration in the industry TFP study.[53] While these operators control sizeable hydroelectric assets, they are not required to file FF1 data, and therefore the data inputs for the TFP study needed to be compiled from alternative primary sources (primarily individual company reports and other financial filings published by the companies themselves). Supplementary information was also obtained through direct communication with the companies.

[53] The 14 federal and municipally owned companies considered for the study were: Bonneville Power Administration, California Department of Water Resources, Chelan County Public Utility District, Columbia Power Corporation, Exelon Power Generation (spun out of Constellation in 2022), Los Angeles Department of Water and Power, New York Power Authority, Seattle City Light, Southeastern Power Administration, Southwestern Power Administration, Tacoma Public Utilities, Tennessee Valley Authority, United States Bureau of Reclamation, and Western Area Power Administration.

For this TFP study, LEI required data associated only with hydroelectric assets. Published data for 10 of the 14 federal and municipally owned companies was only available at the company level, and therefore hydro-specific data was not available. After extensive data research and outreach to the 14 companies, 4 firms were included in the final TFP peer group: Chelan County Public Utility District ("Chelan"), Seattle City Light ("Seattle"), Southeastern Power Administration ("SEPA"), and Western Area Power Administration ("WAPA").

For WAPA, a comprehensive set of hydro-specific data was obtained through publicly available annual reports as well as direct communications with the company.[54] Net generation, revenue, and O&M costs were adjusted to take into account one coal plant owned by WAPA. O&M costs were further adjusted to remove annual transmission-related costs.[55]

Despite data availability, WAPA was excluded from the peer group in the LEI 2016 TFP Study due primarily to concerns over abnormal hydrological conditions. As discussed in the LEI 2016 TFP Study, drought and other hydrological variability around the study end-point, combined with the large size of WAPA's hydroelectric assets, were determined to have the potential to distort the overall industry productivity trends. However, for the current TFP study, LEI has included WAPA in the peer group for two key reasons. First, a longer timeframe helps to mitigate the impact of shorter-term volatility in generation – in WAPA's case, the extension of the study period (2015-2023) resulted in less weight being put on outliers to hydrological conditions. Second, given WAPA's scale,[56] WAPA's inclusion enhances representativeness of the peer group relative to the industry and OPG (as it includes another large hydroelectric generation owner in North America) and thus provides a more complete picture of industry performance.

Nonetheless, it is important to acknowledge that WAPA has historically exhibited volatile generation levels, which could skew the TFP growth rate results depending on the timeframe considered. This volatility is primarily attributable to the hydrological variability experienced across the western United States, where a significant portion of WAPA's hydroelectric assets is located. In recent decades, western states such as California, Arizona, and Nevada (home to WAPA's Central Valley, Parker-Davis, and Boulder Canyon projects) have experienced multiple severe drought cycles. These drought conditions have had a direct impact on reservoir levels and water availability, thereby constraining hydroelectric output and contributing to fluctuations in annual generation. To address this, LEI has relied on the longest timeframe allowed by the

[54] 2002-2011 annual reports for WAPA are not available online. WAPA provided LEI directly with hard copies of their annual reports and statistical appendices for 2002-2011. WAPA annual reports for 2012-2023 can be found here: https://www.wapa.gov/About/the-source/Pages/annual-reports.aspx

[55] Transmission O&M in 2014 was not provided by WAPA – instead, LEI assumed a 41% transmission O&M portion of total O&M, which is consistent with previous years. Transmission O&M in other years were available in the annual reports.

[56] WAPA ranks either as the first or second largest hydroelectric operator in the industry sample, comparable to OPG on several key metrics.

availability of data for WAPA and other peers in the industry, in order to smooth out anomalous periods and better capture long-term performance trends.[57]

SEPA is the other federal company that LEI was able to include in the final peer group. Data for net generation, revenue, and O&M were all available in SEPA's published annual reports.[58] Unlike other federal companies, SEPA does not own any transmission facilities, and therefore O&M figures listed in its annual reports did not need to be adjusted. Revenue figures had to be adjusted to take into account sales of "Purchased Power", which is essentially power sold by SEPA but generated by other operators.[59] This information, provided directly to LEI by SEPA, was subtracted from total revenue to calculate revenue related to the sale of SEPA's hydroelectric energy.

Chelan and Seattle are the only municipally-owned companies that were included in the peer group. Chelan is a new addition to the peer group that was not included in the LEI 2016 TFP Study. Data for Chelan on net generation, O&M, and revenues was compiled from information found within Chelan's published annual reports.[60] Similarly, data for Seattle on net generation and O&M was compiled from Seattle's published annual reports.[61] Seattle's generation facilities are entirely hydroelectric, and therefore generation and O&M data was already in the form necessary for the TFP study. Revenue figures for Seattle had to be estimated, as discussed in Section 4.4.

4.3 Canadian peers

In addition to the 30 US peers above, LEI initially considered 7 Canadian peers: BC Hydro, Brookfield Renewable Partners, Hydro-Quebec, Manitoba Hydro, NB Power, Newfoundland & Labrador Hydro, and TransAlta. To collect the necessary data, LEI reviewed Canadian databases such as StatCan, NERC, company annual reports, regulatory filings where available, and other publicly available information for these companies. While LEI was able to collect production (annual energy generated) and capacity rating data, all 7 companies lacked sufficient publicly available data related to hydro-specific O&M expenses for the entire study timeframe. LEI requested information from each of the 7 Canadian companies regarding such data but was ultimately unable to obtain the information needed for the entire study timeframe. Therefore, due

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[57] Excluding WAPA from the peer group in LEI's analysis does not change the TFP growth rate results materially. The average annual TFP growth rate for the industry, even without WAPA, remains negative at -0.59% (using the physical approach and under the trend regression method).

[58] SEPA annual reports from 2007-2022 can be accessed here: <http://energy.gov/sepa/listings/annual-reports> Hard copy annual reports from 2002-2006 and a digital copy of the 2023 annual report were provided to LEI directly by SEPA.

[59] Based on direct conversations with SEPA, information contained in annual reports, and information on the company's website.

[60] Chelan annual reports from 2012-2023 can be accessed here: <https://www.chelanpud.org/about-us/our-financials/annual-reports> 2002-2011 data was provided to LEI directly by Chelan.

[61] Seattle annual reports can be found here: <https://www.seattle.gov/city-light/about-us/communications/publications>

to the lack of necessary data for the TFP study, these Canadian peers were ultimately excluded from the final peer group.

4.4 Revenue data estimation

As is further discussed later in Section 5.3.3, revenues (less O&M costs) are used to estimate capital input shares, which in turn determine the appropriate weights (α and (1-α)) assigned to the two inputs (capital and O&M). For all peers (except for Chelan), LEI had to perform revenue estimations, because revenue data exclusively from the operation of hydroelectric operations was not obtainable directly from FF1 or other primary sources.

Revenues for all the FF1 peers were estimated using reported production data and reported wholesale energy prices, because energy sales revenues are not directly reported in FF1. Monthly production data came from the EIA-923 dataset, and LEI used historical monthly ISO zone prices for peers operating within ISO markets, or monthly bilateral prices for those operating in non-ISO markets, based on the nearest power price hub traded on ICE.[62] This same process was carried out to estimate Seattle's revenue.

4.5 Purchasing power parity adjustments

Given the data sources, LEI had to make adjustments for currency differences, as revenue and O&M expense figures from US peers are measured in US dollars, while for OPG, those figures are in Canadian dollars. When estimating individual company TFP results, the difference in currencies does not affect results, as a simple scaling up or down of O&M expenses and revenue would result in the exact same outcome. However, in the case of calculating industry TFP trends, Canadian and US figures are summed, and using non-adjusted figures can lead to biases (albeit small) in the TFP results. To adjust for this, LEI inflated all US peer revenue and O&M data by the purchasing power parity ("PPP")[63] for gross domestic product ("GDP") between the US and Canada, as estimated by the OECD.[64] LEI used the 2002-2023 average of 1.20 Canadian dollars per 1 US dollar; however, sanity checks using 2002 (start year) and 2023 (end year) PPP values produced similar industry TFP results.

---

[62] For peers in SERC, posted bilateral prices were utilized. Certain hubs in the Pacific Northwest are not consistently traded, so LEI extrapolated to nearby hubs which were more liquid. Dominion joined PJM in 2005, so ISO prices are not available before then; LEI extrapolated based on VACAR zone prices reported in Platts' Megawatt Daily.

[63] PPP reflects the rate of currency conversion between two countries in relation to the reflective purchasing power of a unit of currency in each country. PPP is much more useful than exchange rates when comparing values between countries, because it better takes account of non-tradable prices and is not as volatile.

[64] LEI chose to inflate US data instead of deflating OPG data because this is a Canadian study. The inflation of US revenue and O&M data did not affect individual TFP results for OPG and US peers, as it only causes a linear shift in data. The effects of the US data inflation can only be seen when comparing US peers with OPG, with the only effect being that US peers make up a larger part of the industry than they would have if data was not adjusted.

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5 Key components of the TFP analysis

In this analysis, as in the LEI 2016 TFP Study, LEI used a single output corresponding to the hydroelectric companies' generation measured in MWh, and two inputs: measures of capital and O&M costs. For capital costs, LEI employed two distinct approaches. The first approach relied on installed capacity as a measure of capital input. In the second approach, LEI used a monetary approach by building up a real-dollar capital input quantity for each hydroelectric company's generation portfolio, and calculating the capital input price index, in order to obtain capital costs.

5.1 TFP calculations based on Single Output – Two Input Model

In performing the TFP analysis, LEI used a Single Output – Two Input Model. Selecting the appropriate inputs and outputs is a key part of a TFP study. Intuitively, selected inputs and outputs would be those that most accurately represent actual productivity, while also having data that is available and quantifiable. Although there are many dimensions to the hydroelectric industry, and theoretically there are many viable input and output possibilities, not all are readily measurable. After reviewing several academic and regulatory TFP studies, the general consensus was that inputs to a TFP study should include capital and O&M costs, while outputs should reflect key products or services.[65]

For the purposes of this TFP study, LEI determined it would be best to use a single output corresponding to the hydroelectric companies' annual generation measured in MWh, and two inputs corresponding to capital costs and O&M costs. Figure 11 below illustrates the TFP model with a single output and two inputs. Note that index methods employ indices that are constructed from ratios of output and input quantities. Where there are multiple outputs or inputs, weights are used to create composite indices (for example, outputs can be weighted by revenue shares and inputs can be weighted by cost shares). In the case of LEI's selected TFP model presented in Figure 11, input weights are represented by the terms "α" for the O&M share and "(1- α)" for the capital share. The process of identifying assumptions for those input weights is described later in Section 5.3.3.

Figure 11. Calculating the TFP index

$$\textbf{TFP Index} = \frac{\textbf{Output Quantity}}{\textbf{Input Quantities}} = \frac{\textbf{Net Generation}}{\boldsymbol{\alpha} * \textbf{O\&M} + (\mathbf{1} - \boldsymbol{\alpha}) * \textbf{Capital}}$$

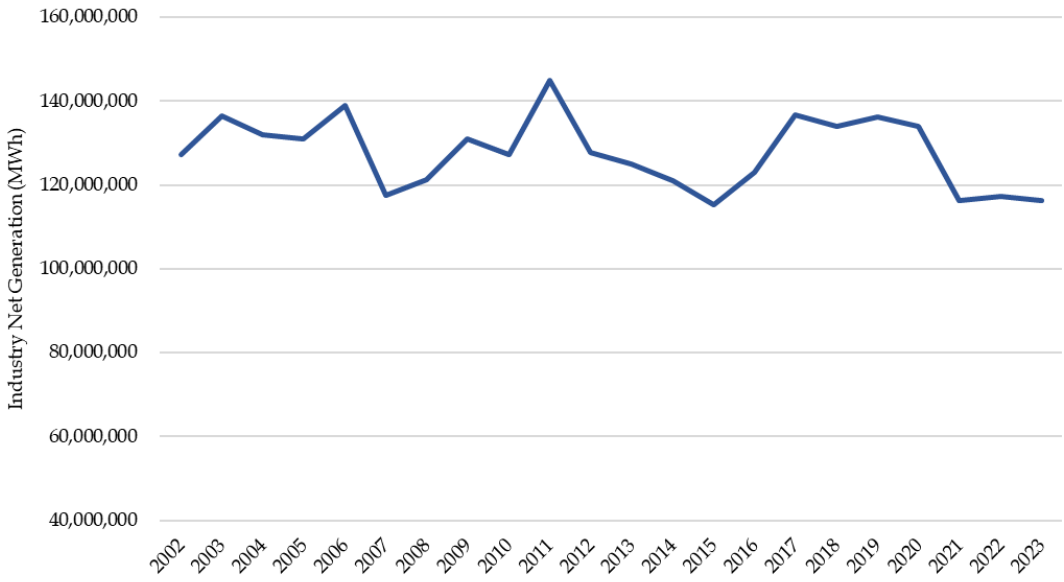
5.2 Output quantities

As noted previously, LEI used a single output measure corresponding to the hydroelectric companies' annual generation, expressed in MWh. In the 2017 Decision, the OEB agreed that generation is the most appropriate output metric, as it is the actual generation produced (rather than capacity) that forms the basis for revenues used to recover capital and operating costs. Figure 12 below presents generation data aggregated across the 20 US peers and OPG over the study period.

[65] More information on the academic and regulatory TFP studies reviewed by LEI can be found in Appendix C.

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Figure 12. Peer group generation across study period



5.3 Input quantities to the TFP index

As discussed previously in Section 3.2.3, there are two possible methods for estimating capital input quantities: a physical method and a monetary method. LEI performed two analyses using each of these methods, in order to show that the ultimate TFP results are generally similar under either approach. Section 5.3.1 describes the capital input quantity under the physical approach, whereas Section 5.3.2 describes in detail the calculation of the capital input quantity for the monetary approach.

5.3.1 O&M input quantity

To calculate quantities of "O&M input", total annual O&M costs are deflated using an appropriate price index, in order to convert a nominal dollar amount into a real monetary amount, which can be a proxy for a quantity measure.

The O&M price index is comprised of a labour price index and a non-labour price index, combined using labour and non-labour cost shares:[66]

- For Canadian data, the labour O&M price index was based on the industrial aggregate average weekly earnings ("AWE") in Ontario (reported by StatCan in current dollars, for

[66] Labour and non-labour O&M price indices for Canada and the US were combined into Canadian and US total O&M price indices using a fixed labour share of total O&M of 62.6%, as suggested by average trends observed in the confidential EUCG HPC database, which includes reported data for 16 hydroelectric generation companies over the 2006-2023 timeframe. The EUCG HPC database was shared with LEI by EUCG for the purposes of this study. LEI was not able to use this data in the TFP study because 22-year datasets (2002-2023) could not be constructed for any of the peers, and 11 of the 16 companies in the EUCG dataset had missing data within the 2006-2023 timeframe.

Canadian utilities, including overtime, seasonally adjusted, for all employees), and the non-labour O&M price index was based on the gross domestic product price index estimate of final domestic demand ("GDP-IPI FDD") in Canada[67] (reported by StatCan).[68]

- For US data, the labour O&M price index was based on the Employment Cost Index ("ECI") data gathered from the US BLS, and the non-labour O&M price index was based on the GDP-PI data gathered from the US BEA.[69]

O&M price indices over the TFP study timeframe are presented in Figure 13 for Canada and in Figure 14 for the US.

Figure 13. Canadian O&M price indices, 2002-2023

Year	Labour Price Index	Non-Labour Price Index	O&M Price Index
2002	1.00	1.00	1.00
2003	1.02	1.02	1.02
2004	1.05	1.03	1.05
2005	1.09	1.06	1.08
2006	1.11	1.08	1.10
2007	1.15	1.11	1.14
2008	1.18	1.14	1.16
2009	1.19	1.15	1.18
2010	1.24	1.16	1.21
2011	1.26	1.19	1.23
2012	1.27	1.21	1.25
2013	1.29	1.23	1.27
2014	1.32	1.26	1.30
2015	1.35	1.28	1.33
2016	1.37	1.29	1.34
2017	1.40	1.31	1.36
2018	1.44	1.33	1.39
2019	1.47	1.35	1.43
2020	1.58	1.38	1.50
2021	1.64	1.43	1.56
2022	1.68	1.52	1.62
2023	1.73	1.57	1.67

Source: StatCan data.

[67] Canada GDP-IPI FDD was approved by the OEB in OPG's previous rate case and has also been used for distribution utilities' rate cases.

[68] These indices are consistent with those used for determination of the inflation (I) factor in the I-X formula for OPG's prescribed hydroelectric assets, as approved by the OEB in the 2017 Decision.

[69] See Section 4.5 for discussion of the PPP adjustment made to get comparability across US and Canadian data.

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Figure 14. US O&M price indices, 2002-2023

Year	Labour Price Index	Non-Labour Price Index	O&M Price Index
2002	1.00	1.00	1.00
2003	1.03	1.02	1.02
2004	1.06	1.05	1.05
2005	1.09	1.08	1.08
2006	1.12	1.11	1.12
2007	1.16	1.14	1.15
2008	1.19	1.17	1.18
2009	1.23	1.17	1.21
2010	1.26	1.19	1.23
2011	1.29	1.21	1.26
2012	1.33	1.23	1.29
2013	1.36	1.25	1.32
2014	1.40	1.28	1.35
2015	1.43	1.29	1.38
2016	1.47	1.30	1.40
2017	1.51	1.32	1.44
2018	1.54	1.35	1.47
2019	1.59	1.38	1.50
2020	1.62	1.40	1.53
2021	1.67	1.46	1.58
2022	1.72	1.56	1.66
2023	1.80	1.62	1.73

Source: US BLS, US BEA.

The total O&M price indices for US and Canada are blended into a North American O&M price index by applying a weight of 15% for the Canadian share of the industry, based on OPG's share of total O&M for the industry (with the remaining 85% attributable to the US share of the industry). Figure 15 below presents the total O&M price index for North America as a whole, whereas Figure 16 shows the growth trend in these indices in graphical form.[70]

[70] North American index was calculated in order to create an industry peer set including both US and Canadian peers.

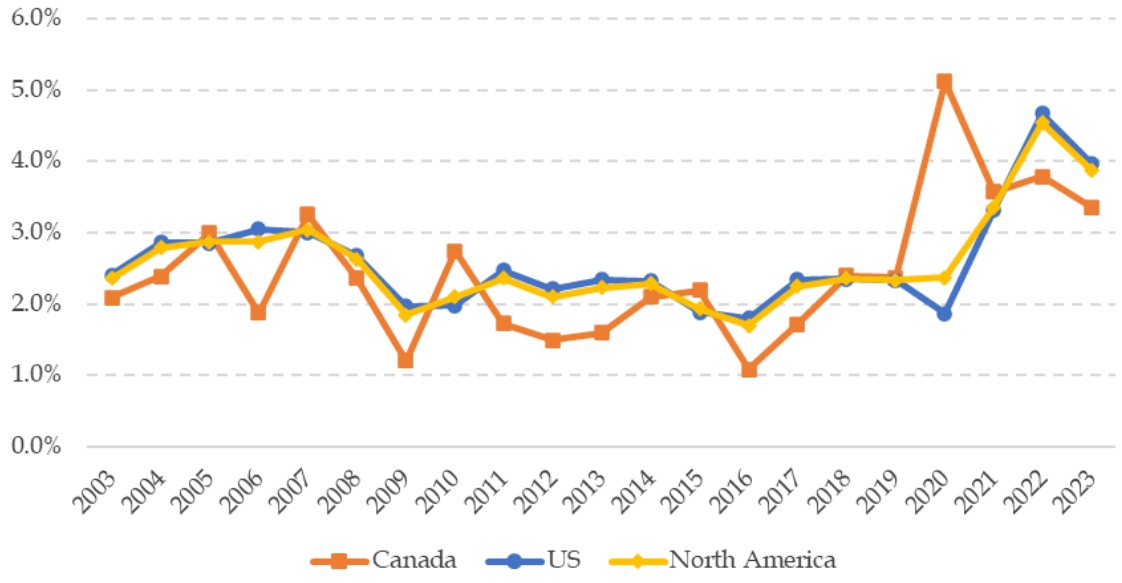
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Figure 15. North American combined O&M price indices, 2002-2023

Year	US O&M Price Index	Canadian O&M Price Index	North American O&M Price Index
2002	1.00	1.00	1.00
2003	1.02	1.02	1.02
2004	1.05	1.05	1.05
2005	1.08	1.08	1.08
2006	1.12	1.10	1.12
2007	1.15	1.14	1.15
2008	1.18	1.16	1.18
2009	1.21	1.18	1.20
2010	1.23	1.21	1.23
2011	1.26	1.23	1.26
2012	1.29	1.25	1.28
2013	1.32	1.27	1.31
2014	1.35	1.30	1.34
2015	1.38	1.33	1.37
2016	1.40	1.34	1.39
2017	1.44	1.36	1.42
2018	1.47	1.39	1.46
2019	1.50	1.43	1.49
2020	1.53	1.50	1.53
2021	1.58	1.56	1.58
2022	1.66	1.62	1.65
2023	1.73	1.67	1.72

Source: StatCan, US BLS, and US BEA.

Figure 16. O&M price index growth rates (%) for US, Canada, and North America



Source: StatCan, US BLS, and US BEA.

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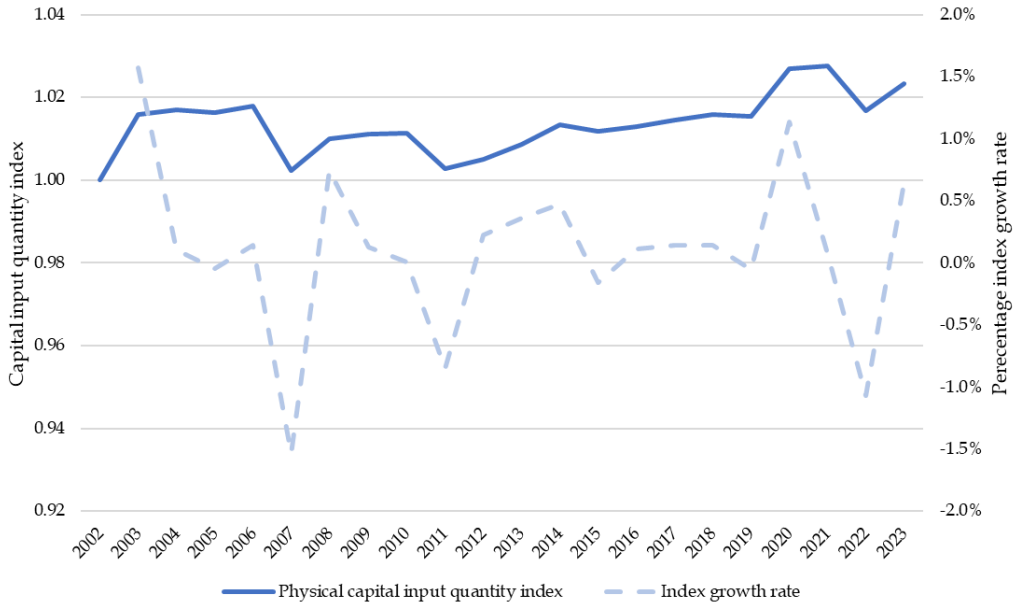
5.3.1 Capital input quantity under the physical method

Under the physical method, the quantity of capital input is measured using physical indicators, namely the installed capacity of hydroelectric generating facilities (expressed in MW). This approach is conceptually straightforward and particularly well-suited to the hydroelectric industry, where capital spending is concentrated at the inception of the large, long-lived physical infrastructure, and with proper maintenance (that also involves some capital investment), the infrastructure can provide a dependable stream of service over time, which is measured by metrics like the MCR.

In contrast to the monetary method, the physical approach does not require assumptions about depreciation rates or the historical cost structure of the assets. Rather, it assumes that the physical proxy measure (MCR) adequately captures the flow of services from the capital stock, including contribution from all structures, turbines, generators, and other physical components that contribute to a power plant's generation capability. Because of this, the physical method inherently reflects the "one hoss shay" depreciation profile characteristic of hydroelectric assets, where asset efficiency remains stable until a sharp decline at the end of life, rather than a gradual decay. The physical method therefore avoids several analytical pitfalls inherent in the monetary approach, such as distortions caused by unrealistic depreciation assumptions. Use of unrealistic depreciation profiles (like a geometric depreciation or straight-line depreciation profile) can lead to a systematic underestimation of the capital stock over time and inflation of the resulting TFP growth rates. In contrast, by using MCR (MW) as a proxy, the physical method provides a more stable and transparent measure of capital input that is not distorted by changes in accounting conventions, inflation adjustments, or ownership histories.

Figure 17 below shows the physical capital (MW) input quantity index and the corresponding year-over-year index growth rate across the study period for the industry sample comprised of 20 US peers plus OPG.

Figure 17. Physical capital input quantity index and growth rate (2002-2023)



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5.3.2 Capital input quantity under the monetary method

To estimate the capital input quantity using the monetary method, we begin with the firm's gross book value of capital assets. Because this book value reflects assets acquired in different years and in nominal terms, it must first be deflated using an appropriate capital cost index to convert it into constant dollar terms. Once the capital stock has been expressed in real dollars, it is then weighted by an implicit rental price index to determine the contribution of capital inputs to total factor productivity. This rental price reflects the cost of using capital over time and incorporates key economic variables such as depreciation, inflation, the cost of capital, and tax effects. The resulting capital input quantity is thus expressed as the real value of capital employed, adjusted to reflect its economic service cost.

5.3.2.1 Perpetual inventory equation

In the monetary method, LEI obtained the quantity of capital stock using the perpetual inventory equation, which has been adopted in numerous TFP studies used in ratemaking globally.[71] To calculate the capital stock in the current year (K_t), the perpetual inventory equation takes the end of year capital stock (gross book value) from the previous year (K_{t-1}) and adds in the gross book value of new additions (I) and deducts the gross book value of retirements (R) in year t. The new additions and retirement data were collected directly from FF1 on a company level.[72] However, because the retirements in FF1 incorporate the monetary value of assets at different points in time (therefore mixing and summing nominal dollars from different years), the capital additions and retirements must be inflated and deflated to represent uniform real dollar terms. To do this, LEI used the Handy Whitman Cost Index ("HWI")[73] for Hydraulic Production Plant to represent all retirements and additions in 2002 dollars, which reflects the start year of the TFP study timeframe. The trend in HWI going back over a century is illustrated in Figure 18 below.

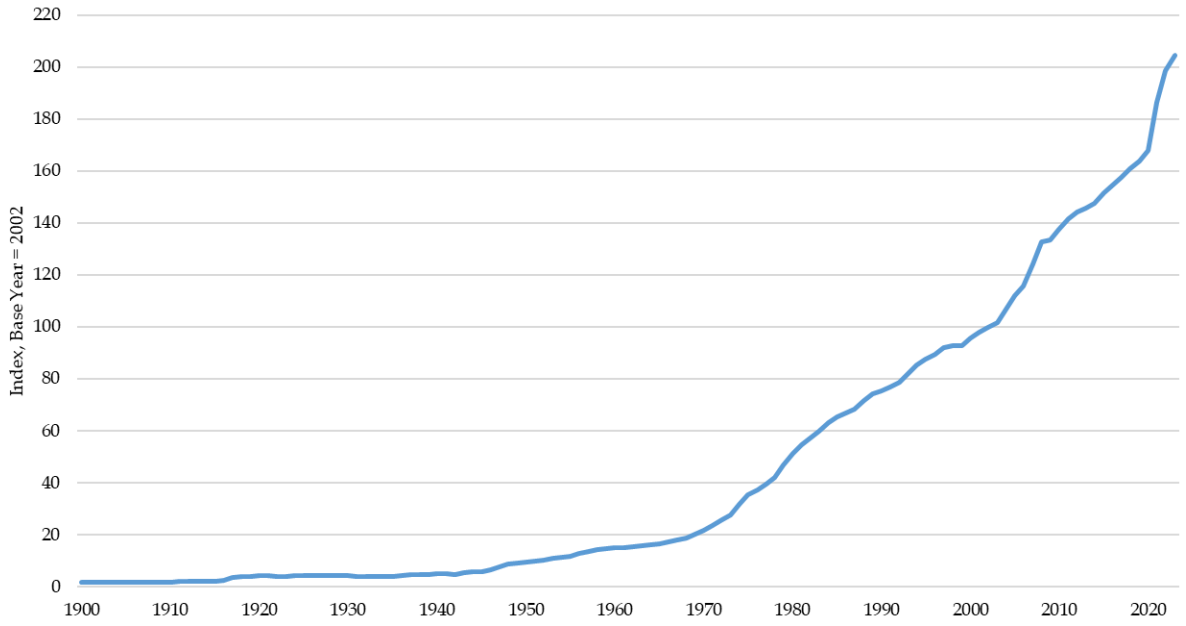
[71] This approach has been used in TFP studies that were accepted by regulators in Alberta, Australia, the United Kingdom, and Massachusetts.

[72] As noted previously in Section 4.1.3, because LEI relied on FF1 data for the monetary method, not all of the peers from the physical method analysis could be included. This is another benefit of using the physical method.

[73] HWI calculates the cost trends for different types of utility construction. The index highlighted in Figure 18 and relied upon for this TFP study focused on hydroelectric generation. It is used in many TFP studies to trend earlier capital asset costs and estimate reproduction costs at prices prevailing at a chosen base year.

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Figure 18. Illustration of the Handy Whitman Index for hydraulic production plant construction in North America, indexed to 2002



Source: LEI analysis based on HWI data

Capital additions are recorded in nominal dollars at time t, annual capex values are therefore divided by the HWI also at time t. The adjustment to retirements is more complicated. The retirements are capital assets that are assumed to have exhausted their service life. Because retirements are recorded at their original historical cost, they need to be re-based (inflated) to reflect their full monetary value in real dollar terms at retirement (i.e., t minus the average service life s). The equation for estimating the real capital quantity in any given year t under the perpetual inventory formula is shown below:

$$K_t = K_{t-1}\frac{I_t}{HWI_t} - \frac{R_t}{HWI_{t-s}}$$

The first year for which one estimates the capital input quantity is called the "Benchmark Year". The best available information to construct a benchmark value is the gross book value of all capital assets and equipment from FF1, which is made up of assets of different vintages. The capital stock measure is sensitive to the age of the various capital components in the gross book value. To improve the precision of the capital stock estimates for the years in the TFP study, it is useful to select a benchmark year that is well before the beginning of the TFP study period (in the case of LEI's TFP study, the first year of the study period is 2002). LEI selected a benchmark year of 1994 as that was a year where data was readily available in digital form for FF1 peers.[74]

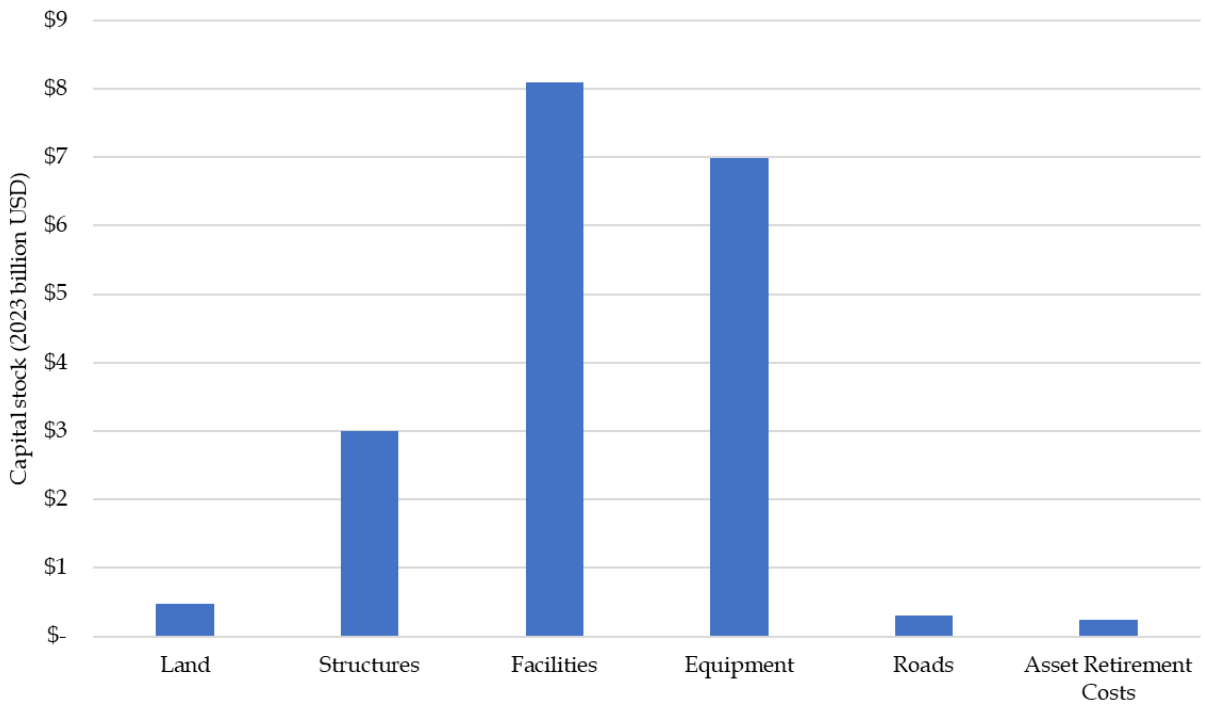
[74] For OPG specifically, LEI obtained re-assessed plant valuations (i.e., market value) in terms of gross book value in 1999. Therefore, for OPG specifically, LEI rebased this capital stock to 2002 dollars (the base year).

Once the benchmark year capital quantity was established, the capital flow in each subsequent year is added by the new capital additions (divided by the HWI value in the year that capital was added) minus any retirements (re-based by the growth in the HWI since the equipment was assumed to be put into service, based on the average service life).

5.3.2.2 Service life assumption in the perpetual inventory equation

For hydroelectric companies, FF1 data breaks down the capital components by asset type for each plant. These components include land, structures, facilities, equipment, roads, and asset retirement costs.[75] Figure 19 below shows the aggregate gross book value for US peers in the TFP study by asset type as of 2023, demonstrating that facilities and equipment account for the majority of capital value.

Figure 19. Aggregate book value for all US peers per asset type (2023 USD billion)



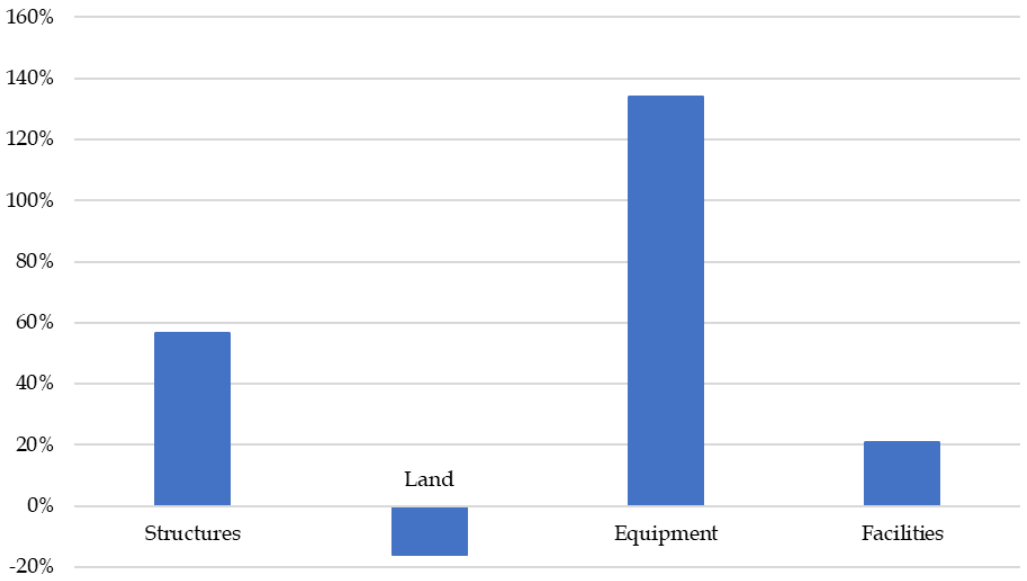
The assets within each asset type are not itemized; therefore, it is impossible to know precisely the exact vintage of each component of capital stock. However, a review of the year-by-year gross asset values by asset type in FF1 provides a clear trend. The value of land, structures, facilities,

[75] FF1 reporting organizes these capital additions and retirements under specific account codes: land is reported under Account (330) Land and Land Rights; structures fall under Account (331) Structures and Improvements; facilities fall under Account (332) Reservoirs, Dams, and Waterways; equipment falls under three accounts: (333) Water Wheels, Turbines, and Generators, (334) Accessory Electric Equipment, and (335) Miscellaneous Power Plant Equipment; roads fall under Account (336) Roads, Railroads, and Bridges; hydroelectric retirements fall under Account (337) Asset Retirement Costs for Hydraulic Production.

and roads is not typically increasing over time.[76] Therefore, LEI assumed that the dollar values reported for these asset classes date back to when the plant was placed in service. On the other hand, equipment gross asset values are increasing with time (in nominal terms) as plant owners replace and upgrade equipment. By tracking changes in gross book value at the plant level, LEI believes most additions and retirements occurring over time fall under the equipment category, and therefore to apply OHS, we rely on the average service life of equipment. For that reason, LEI inflated the equipment asset class based on the HWI associated with the midpoint between the plant in-service year and 1994 (the benchmark year for this TFP study). These estimates at the plant level were then rolled up to the company level.

To further confirm LEI's understanding that most additions and retirements occurring over time fall under the equipment asset class, LEI compared the change in book value in OPG's technical depreciation data between 2013 and 2024. LEI found that the book value for equipment increased considerably more than the book value for any other class of asset (structures, facilities, or land) – see Figure 20 below.

Figure 20. Average percentage change in book value per asset class (2013 vs 2024 OPG technical depreciation data)



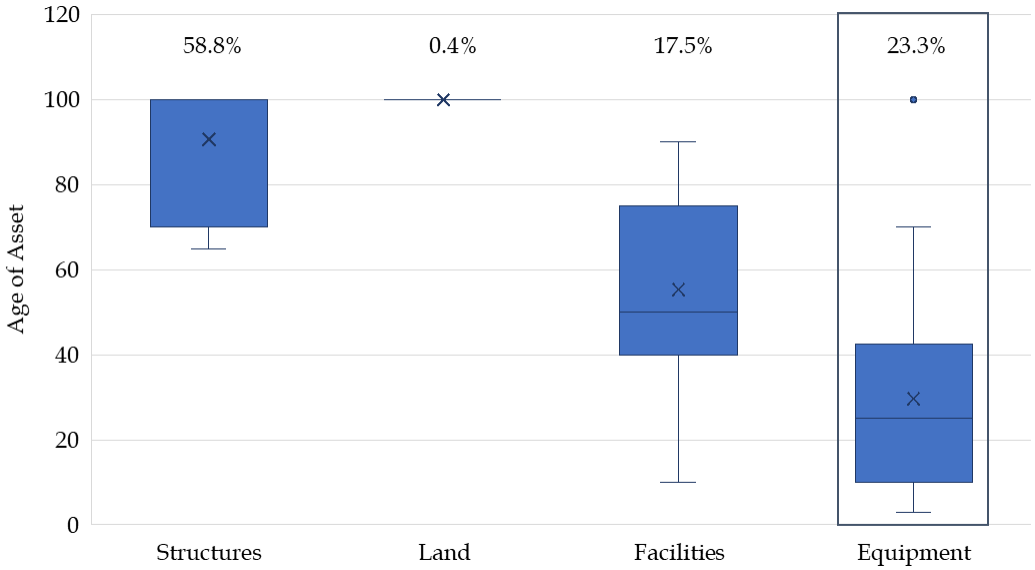
Source: OPG 2013 and 2024 technical depreciation data.

Accordingly, for the monetary approach, LEI based the average service life assumption for purposes of accounting for retirements and therefore physical depreciation of capital input

[76] The International Renewable Energy Agency ("IRENA") echoes this observation, noting that there are *"many examples of hydropower plants that have been in operation for more than 100 years with regular upgrading of electrical and mechanical systems but no major upgrades of the most expensive civil structures (dams, tunnels)."* See IRENA, Renewable Energy Technologies: Cost Analysis Series. Volume 1: Power Sector, Issue 3/5. June 2012. <https://www.irena.org/documentdownloads/publications/re_technologies_cost_analysis-hydropower.pdf>

quantities on the equipment class of assets. Specifically, LEI assumed an average service life of 43 years for any retired capital, which is based on OPG's average book-value-prorated asset life for the equipment class of assets.[77] Figure 21 below shows the range of service lives specified for each type of asset in use at hydroelectric power plants, based on OPG's 2024 technical depreciation data. This estimate is generally in line with other depreciation studies reviewed by LEI, where the average service life for station equipment averaged 48.5 years among studies reviewed.[78] In respect of the other asset components – structures, facilities, land – LEI essentially assumed that those are not physically deteriorating, and therefore we do not need a service life assumption.

Figure 21. Range of service lives by asset type in use at hydroelectric power plants (years)



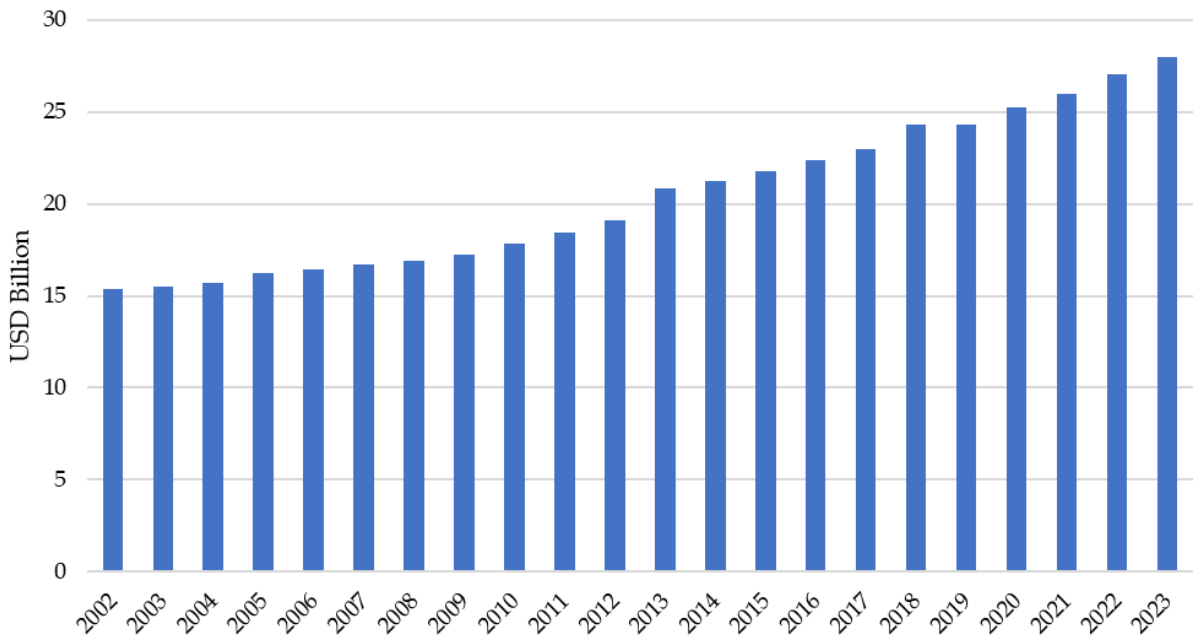
Source: OPG 2024 technical depreciation data.
* Percentages indicate the share of each hydroelectric asset type relative to the gross book value of total plant.

Figure 22 below shows the resulting real capital stock used in this TFP study using the monetary approach from 2002 to 2023 for the hydroelectric industry (this is an aggregation of the real capital stock series for all 17 hydroelectric companies, including OPG, in the industry peer group).

[77] LEI excluded main rotational equipment, turbines, and governors from this calculation, as they did not exhibit an appreciable change in book value between 2013 and 2024.

[78] In addition to OPG's technical depreciation data, LEI reviewed depreciation studies from the following firms: Pacific Gas and Electric (2023), Avista (2021), Duke Energy Carolinas (2021), Idaho Power Company (2021), Southern California Edison (2021), Appalachian Power Company (2019), Portland General Electric Company (2019), PacifiCorp (2017), Duke Energy Progress (2016), New York State Electric Gas and Corporation (2015), and South California Gas and Electric (2009).

Figure 22. Real capital stock for the hydroelectric industry (17 hydroelectric companies), 2002 dollars



5.3.3 Input share weights in the TFP index

Given that LEI is using two inputs for the TFP study (capital and O&M costs), weights or cost shares must be used to combine the sub-indices into a composite input quantity index. Capital cost input shares may be estimated using two methods, an endogenous or an exogenous approach, as further described in the textbox on the next page.

The two approaches should produce similar TFP results. Because LEI did not readily have financial data on capital costs available when first calculating the physical approach, LEI elected to use the endogenous approach to estimate cost input shares in the LEI 2016 TFP Study and continued to do the same for this TFP study (see Section 5.3.3.1 for further details). However, for purposes of proving that the TFP results are similar, LEI also calculated a capital price index while using the monetary approach and therefore used the exogenous approach to estimate cost input shares (see Section 5.3.3.2 for further details). The two capital input price methods, exogenous and endogenous, can be used interchangeably with both the physical and monetary approaches to calculating capital input quantities. LEI tested that concept by applying both methods of estimating cost input shares to the varying capital input quantity methods; there was no material difference in the TFP results.

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Capital input share

Capital cost input shares may be estimated using two methods, an endogenous or an exogenous approach. The endogenous approach is the residual of revenue less operating costs; this assumes prices are sufficient to cover efficient costs and provide an appropriate return on and of capital. The endogenous approach is appropriate for competitive conditions, or if a firm has been regulated for an extended period under a cost-of-service methodology, such that revenues cover costs.

LEI used the endogenous approach (revenue = costs) to determine capital input shares for the physical approach to measuring capital costs, as it is easier to implement and is expected to provide a reasonable approximation of capital inputs in the business.

The exogenous approach is calculated by forming a user cost measure based on an estimated depreciation rate, a rate of return on capital, a deduction for the estimated rate of capital gains or addition for capital losses (i.e., annual change in the asset price index), and applied to a starting point asset value (capital stock). It also recognizes that there has to be a "return of" capital over the asset's lifetime (i.e., the firm has to recoup its original investment) and a "return on" capital to compensate for holding the asset over its lifetime, reflecting the opportunity cost of using the funds in an alternative investment. The exogenous approach must also consider that capital gains resulting from an increase in the price of the asset reduce the cost of holding (and using) the asset over the year. The exogenous approach also requires making a judgment on the firm's true opportunity cost of capital, and usually assumes geometric depreciation of capital.

LEI used the exogenous approach to determine capital input shares for the monetary approach to measuring capital cost, and this resulted in a similar TFP growth trend as using the endogenous capital input shares and the physical approach.

5.3.3.1 Capital cost input shares under the physical method

Under the physical method, LEI determined the capital share as the share of the estimated cost of capital to total costs (revenues less total O&M). Based on combined industry business operations data, the capital share for the 2002-2023 period averaged 75% for the industry as a whole. These industry-level capital shares, which can be seen in Figure 23 below, were calculated by LEI using firm-specific data.

Figure 23. Annual implied capital to total O&M shares for hydroelectric generation industry under the physical approach/endogenous method

Year	Capital Share	O&M Share
2002	83%	17%
2003	85%	15%
2004	84%	16%
2005	85%	15%
2006	83%	17%
2007	79%	21%
2008	81%	19%
2009	75%	25%
2010	74%	26%
2011	74%	26%
2012	67%	33%
2013	73%	27%
2014	75%	25%
2015	69%	31%
2016	68%	32%
2017	71%	29%
2018	70%	30%
2019	72%	28%
2020	67%	33%
2021	72%	28%
2022	79%	21%
2023	73%	27%
Average	**75%**	**25%**

Source: Based on LEI internal analysis, using data sources described previously in Section 4.

5.3.3.2 Capital input price index under the monetary method

For the monetary method, unlike the physical method, LEI applied the exogenous approach to calculating the capital quantity (although it can technically be applied to both the physical and monetary TFP). This is because the capital input price calculated in the exogenous approach represents the implicit rental price or cost to a user corresponding to a unit of capital quantity. Unlike the O&M input price index, the capital input price index is not used to deflate the capital input quantity. Instead, the capital input price index is used to weight the capital input quantity in the total input quantity index over time (mechanically, this is achieved by multiplying the capital input quantity by the capital input price index, which results in the total capital quantity value that is then represented as a cost share in the calculation of the composite input index and

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the resulting TFP index).[79] Essentially, the calculation of the capital input price index allows for implementation of the exogenous method for weighting O&M and capital inputs.

The capital input price formula used in LEI's analysis was derived from a price formula developed in the L.R. Christensen and D.W. Jorgenson (1969) paper,[80] and is also explained in a paper by R.E. Hall and D.W. Jorgenson (1967).[81] Capital input price formulae similar to LEI's formula are in widespread use in productivity studies around the world. The price of capital under this approach is based on an equilibrium relationship between the price an investor is willing to pay for an asset and the after-tax expected value of services that the asset will provide over the asset's lifetime. This relationship is called the implicit rental price formula, which is described in more detail in Appendix B.

[79] The exogenous approach to weighting the capital input quantity is sometimes referred to as the "direct" approach, as the annual cost of using capital inputs can be measured directly by applying the sum of an estimated depreciation rate and a rate reflecting the opportunity cost of capital to the value of the assets. This is different from an endogenous approach used in the physical method, which assumes that the capital cost weighting is the residual of the utility's total revenue minus OM&A.

[80] L.R. Christensen and D.W. Jorgenson (1969), "The Measurement of Real Capital Input, 1929 – 1967," Review of Income and Wealth, Series 15, No. 4, December, pp. 293-320.

[81] R.E. Hall and D.W. Jorgenson. "Tax Policy and Investment Behavior." The American Economic Review. vol. 57, no. 3, 1967, pp. 391–414. Equation (6) in this paper is very similar to LEI's formula, except that: (1) LEI's formula assumes that there is no investment tax credit; (2) an expected inflation term should be included, consistent with dynamic expectations; and (3) there is no explicit term for depreciation, but instead an annuity form is preferred to ensure full recovery of the cost of capital.

6 Industry TFP results

This section of the report presents the TFP results for the hydroelectric industry under both the physical and monetary approaches. LEI used a Single Output – Two Input Model as outlined previously in Section 5, based on plant and company level data collected from 2002 through 2023. For the industry consisting of 20 US peers plus OPG, using data from 2002-2023, LEI calculated the TFP growth rate to be -0.40% per annum using a physical measure of capital input and the 'trend regression' method of estimating the TFP growth rate. Using a monetary approach to measuring capital input, and a slightly reduced peer group (16 US peers plus OPG) due to data availability issues, LEI calculated a TFP growth rate of -1.01% per annum using the 'trend regression' method. For comparison purposes, if LEI had used the same reduced peer group for the physical approach as for the monetary approach, the TFP growth rate would have been -0.61%.

Figure 24. Average annual TFP growth rate over 2002-2023 period using the trend regression method

Measure of capital input	Peer group	TFP growth rate
Physical	20 US peers plus OPG	-0.40%
Monetary	16 US peers plus OPG	-1.01%
Physical	16 US peers plus OPG	-0.61%

6.1 TFP growth pursuant to the physical method for measuring capital input quantities

LEI collected data from 20 US peers plus OPG for the physical method of estimating capital input quantities. The TFP formula is shown in Figure 25 below, where:

- output is measured as net generation (MWh);
- inputs include capital measured as capacity (MW) and O&M costs deflated by an O&M price index in order to yield quantities of O&M;
- the capital share was estimated to be 75% and the O&M share was estimated to be 25%;
- the implicit labour share in O&M was estimated to be 62%; and
- the labour price index and non-labour price indexes were O&M-weighted blends for the North American hydroelectric peer industry using Canadian and US labour and non-labour price indexes.

Figure 25. Final TFP index

$$TFP = \frac{Output\ Quantity}{Input\ Quantities} = \frac{Net\ generation\ quantity\ index}{25\% * \frac{O\&M\ quantity\ index}{38\% * Non-labour\ price\ index + 62\% * Labour\ price\ index} + 75\% * Capital\ quantity\ index}$$

As observed in Figure 26 below, the annual growth rates for capital inputs measured in MW varied between -1.53% (2006-2007) and 1.57% (2002-2003) over the 2002-2023 period, although year-over-year fluctuations were mostly modest. This result is to be expected for a mature

hydroelectric industry, as the physical capability of a hydroelectric power plant is usually set when it is first constructed and then maintained through proper maintenance and repairs. Moreover, construction of new hydroelectric generation facilities is relatively rare in North America. Annual O&M input quantity growth varied between -4.45% (2016-2017) and 7.65% (2002-2003). O&M input quantities exhibited greater volatility in year-over-year growth rates than capital input quantities. The annual growth rates for the output quantity index exhibited even greater year-over-year volatility, ranging between -16.65% (2006-2007) and 12.96% (2010-2011) over the study period. This volatility is not surprising given the influence of weather on hydroelectric generation. The study timeframe covers a sufficiently long timeframe that a variety of hydrological conditions are captured.

Figure 26. Quantity sub-index growth rates for inputs and output

	Quantity Sub-Index Growth Rates		
Year	Input (K) weight 75%	Input (O&M) weight 25%	Output (MWh) weight 100%
2002-2003	1.57%	7.65%	7.07%
2003-2004	0.11%	1.31%	-3.33%
2004-2005	-0.05%	2.14%	-0.75%
2005-2006	0.15%	2.92%	5.86%
2006-2007	-1.53%	4.92%	-16.65%
2007-2008	0.75%	5.66%	3.04%
2008-2009	0.12%	0.02%	7.68%
2009-2010	0.01%	1.54%	-2.87%
2010-2011	-0.85%	-3.73%	12.96%
2011-2012	0.23%	1.01%	-12.56%
2012-2013	0.36%	-2.38%	-2.21%
2013-2014	0.47%	-1.92%	-3.31%
2014-2015	-0.16%	3.55%	-4.67%
2015-2016	0.11%	-0.72%	6.45%
2016-2017	0.14%	-4.45%	10.52%
2017-2018	0.14%	5.12%	-2.11%
2018-2019	-0.06%	-4.21%	1.77%
2019-2020	1.14%	-1.79%	-1.76%
2020-2021	0.08%	1.16%	-14.16%
2021-2022	-1.07%	-3.09%	0.83%
2022-2023	0.64%	4.42%	-0.68%

The resulting weighted total input index growth rates and TFP index growth rates are illustrated in Figure 27 below.

Figure 27. Input, output, and physical TFP index annual growth rates

Year	Quantity Sub-Index Growth Rates		
	Input Index Growth	Output Index Growth	TFP Index Growth
2002-2003	2.57%	7.07%	4.50%
2003-2004	0.30%	-3.33%	-3.62%
2004-2005	0.29%	-0.75%	-1.04%
2005-2006	0.59%	5.86%	5.27%
2006-2007	-0.32%	-16.65%	-16.33%
2007-2008	1.72%	3.04%	1.33%
2008-2009	0.10%	7.68%	7.58%
2009-2010	0.41%	-2.87%	-3.28%
2010-2011	-1.60%	12.96%	14.56%
2011-2012	0.46%	-12.56%	-13.02%
2012-2013	-0.46%	-2.21%	-1.75%
2013-2014	-0.15%	-3.31%	-3.16%
2014-2015	0.88%	-4.67%	-5.56%
2015-2016	-0.15%	6.45%	6.60%
2016-2017	-1.24%	10.52%	11.77%
2017-2018	1.59%	-2.11%	-3.70%
2018-2019	-1.26%	1.77%	3.03%
2019-2020	0.24%	-1.76%	-2.00%
2020-2021	0.41%	-14.16%	-14.57%
2021-2022	-1.57%	0.83%	2.40%
2022-2023	1.55%	-0.68%	-2.23%

The trend regression method takes the year-over-year index growth rates and plots a line of best fit. The slope of this line of best fit, or linear trend, is the estimated annual average TFP growth rate. Unlike the average method, where the index values at the start and end influence the outcome, under the 'trend regression' method, each annual observation is considered. As discussed previously in Section 3.2.5, this additional regression step is useful in establishing unbiased trends in instances where a series exhibits volatility at its endpoints.

Figure 28 below illustrates the final formula for calculating the physical TFP growth rate using this method, while Figure 29 provides a visual representation of the results from this process; the slope of the line is the estimate of the TFP growth rate from 2002-2023 using the 'trend regression' method.

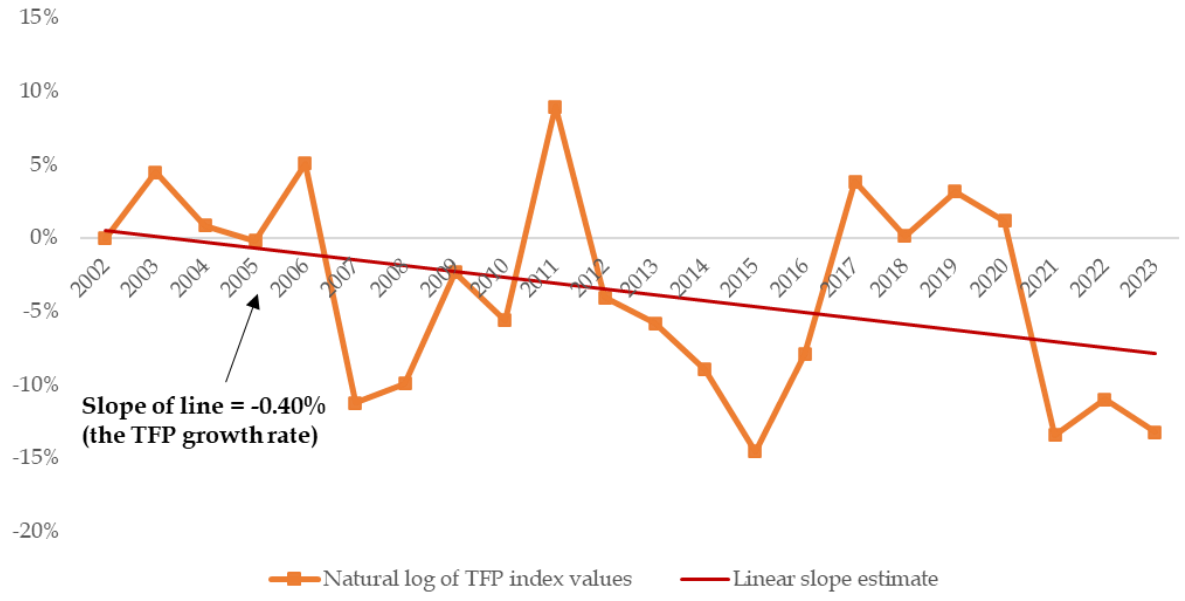
Figure 28. Equation of line under 'trend regression' method

$$\ln(\text{industry TFP index}) = -0.40\% * \mathrm{T} + 0.96\%$$

Where:
$\ln(\text{industry TFP index})$ = natural logarithm of TFP index values from $2002 - 2023$
-0.40% = trend growth rate for the industry TFP index over the study period
T = time in years $(0, \ldots, 21)$
0.96% = constant term

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Figure 29. Natural log of TFP index values and linear slope estimate



This same method of analysis can be carried out on the input and output index values to calculate their respective growth rates under the 'trend regression method'. As summarized in Figure 30 below, using the trend regression method, the input index average growth rate was estimated to be 0.07% and the output index shrank at an average rate of -0.33%. The combined trends of the input and output index yield a growth rate of -0.40% for the hydroelectric industry TFP under the physical method.

Figure 30. Key TFP study results using the trend regression method

Trend estimate of index growth rates (2002-2023)		
Input Index	**Output Index**	**TFP Index**
0.07%	**-0.33%**	**-0.40%**

LEI believes that a negative TFP trend is to be expected for mature hydroelectric businesses, because of the fixed production capability and rising costs of maintenance through the life cycle of a hydroelectric resource. As discussed earlier in Section 3.1, common drivers of productivity include technological innovation and improved economies of scale. However, for a mature hydroelectric business, great leaps forward in technology are extremely rare and economies of scale are generally fixed as soon as the asset is built and put into operation (although occasionally, refurbishments and other capital programs can increase energy production due to advances in new equipment). In general, it should be expected that output levels would be stable over time,[82] capital inputs are constant (once a hydroelectric plant is put into service), and OM&A inputs

[82] Assuming constant water flow levels over the course of the study and given generator design is fixed once the asset is brought into service, unless there are refurbishments that increase output.

would likely be increasing over time (in order to maintain asset operational capability as the asset ages).

6.2 TFP growth pursuant to the monetary method for measuring capital input quantities

Remember that growth in the industry's productivity is measured by the difference between the growth rate of the industry's outputs and the growth rate of the industry's inputs. Using the monetary approach, LEI calculated that the industry TFP in the FF1 peer group shrank by -1.01% per year over the 2002-2023 timeframe when using the trend regression approach. For comparison purposes, LEI calculated a TFP growth trend using the physical approach on the same reduced peer group as used for the monetary approach TFP study, resulting in a TFP value of -0.61%. Figure 31 below compares the TFP annual growth rates for the monetary and physical approaches.

Figure 31. TFP growth rates using the monetary and physical approaches

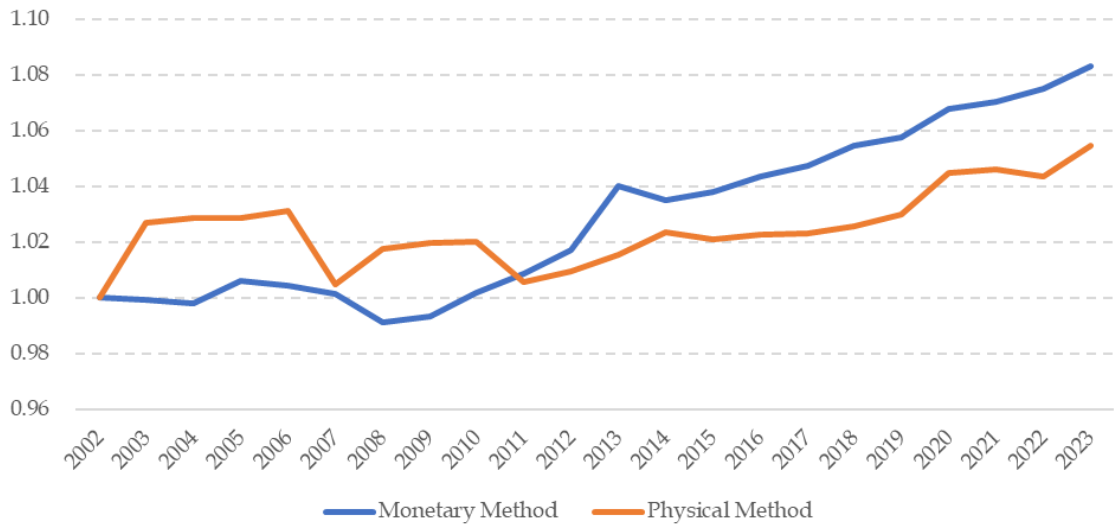
Year	Monetary TFP	Physical TFP
2003	8.3%	4.5%
2004	-3.1%	-3.6%
2005	0.5%	-1.0%
2006	5.0%	5.3%
2007	-19.9%	-16.3%
2008	8.3%	1.3%
2009	9.1%	7.6%
2010	-8.2%	-3.3%
2011	5.5%	14.6%
2012	-15.6%	-13.0%
2013	-0.2%	-1.7%
2014	-4.4%	-3.2%
2015	-6.1%	-5.6%
2016	9.1%	6.6%
2017	12.3%	11.8%
2018	-6.4%	-3.7%
2019	4.5%	3.0%
2020	-7.6%	-2.0%
2021	-11.8%	-14.6%
2022	5.6%	2.4%
2023	3.0%	-2.2%

6.2.1 Input index

The composite input index is based on the combination of the capital and O&M input quantity indices. The only difference between the monetary and physical approaches to the TFP calculation is the capital input quantity index, as the O&M and output indices remained the same. Figure 32 below illustrates a comparison of the capital input quantity indices calculated using both the monetary and physical approaches for the same 16 FF1 peers and OPG. Although the

year-over-year trends vary in some instances, the overall trend over the timeframe of the TFP study is very similar.

Figure 32. Comparison of the capital input quantity indices (monetary versus physical methods)



The capital input quantity index, calculated using the monetary approach, grew at an annual average rate of 0.38% between 2002 and 2023, compared to 0.25% using the physical approach. This observation implies that under both methods, the rate of capital input quantity growth has remained fairly modest for the hydroelectric industry.[83] This is consistent with the hypothesis around the relative magnitude of the initial capital investment versus the more modest periodic capital spending to maintain the operational capability of hydroelectric power plants.[84]

6.2.2 Industry TFP results

As noted previously, the monetary approach TFP results are based on a 17-company industry sample (16 US FF1 peers plus OPG). For comparison purposes, LEI calculated a TFP growth trend using the physical approach and the same reduced peer group as used for the monetary approach TFP study. As summarized in Figure 33 below, using the trend regression method, the input index growth rate of 0.42% and the output index growth rate of -0.59% combined into a study-period estimated annual monetary TFP growth rate of -1.01%. This result can be compared to the

[83] Based on data from EIA, on average, from 2013 to 2023, hydroelectric summer capacity across all power plants in the United States only grew by 0.09% per annum. Source: EIA. *Electric Power Annual.* <https://www.eia.gov/electricity/annual/>

[84] Sustaining capital expenditures for hydroelectric assets tend to follow a cyclical pattern. Spending may be modest for several years during steady-state operations, but eventually increases significantly during major overhauls or refurbishments, which can persist for an extended period before tapering again. This cyclical investment pattern is consistent with the "bathtub curve" typically used to describe asset reliability and failure rates across the lifecycle of hydroelectric equipment. An exception to this cycle is when a life extension program is undertaken, which involves substantial investment beyond regular maintenance.

trend regression method in the physical approach to the TFP using that same peer group, which yielded a TFP growth rate of -0.61%.

The TFP growth rate estimated in this study follows a similar trend to the findings of the LEI 2016 TFP Study, which reported a -1.18% industry average TFP growth rate (for the 2002-2014 timeframe) using the 'trend regression' method and the physical approach to measuring capital input. The slightly less negative TFP results in the current study reflects a recent trend observed among the US peers of higher generation output in the additional years of the study (2015-2023), as well as the addition of WAPA, who, because of its size, contributes to the TFP growth rate to be slightly less negative. Overall, the higher generation output per unit of inputs results in higher productivity and a slightly less negative productivity growth.

Figure 33. Key TFP study results using the trend regression method

Trend estimate of index growth rates (2002-2023)				
Measure of capital input	Peer group	Input Index	Output Index	TFP Index
Physical	20 US peers plus OPG	0.07%	-0.33%	-0.40%
Physical	16 US peers plus OPG	0.02%	-0.59%	-0.61%
Monetary	16 US peers plus OPG	0.42%	-0.59%	-1.01%

Additionally, LEI's TFP model yields negative TFP growth rate results for the hydroelectric generation industry, regardless of the timeframe studied and regardless of whether the physical approach or monetary approach for measuring capital input quantities is used.[85] Figure 34 below summarizes the TFP growth rates for the physical and monetary models over 15- and 20-year periods, rather than the 22-year timeframe examined above.

Figure 34. Key TFP study results under different timeframes

Timeframe	Measure of capital input	Peer group	Average TFP growth rate	'Trend' TFP growth rate
15 years (2009-2023)	Physical	20 US peers plus OPG	-0.78%	-0.49%
20 years (2004-2023)	Physical	20 US peers plus OPG	-0.74%	-0.34%
15 years (2009-2023)	Monetary	16 US peers plus OPG	-1.40%	-0.41%
20 years (2004-2023)	Monetary	16 US peers plus OPG	-0.92%	-0.88%

[85] LEI continues to believe that the regulated company (such as OPG) should be part of the industry that is being examined for purposes of setting an X factor for that company, unless it can be shown that its productivity trends are truly outside the norm and distort the industry trend. Removing OPG from the peer group in LEI's analysis does not change the TFP growth rate results materially. The average annual TFP growth rate for the industry, even without OPG, remains negative at -0.87% for the physical method and -0.40% for the monetary method using the 'trend regression' method of estimating the growth rate.

7 Concluding remarks

This report details the results of LEI's TFP study of the North American hydroelectric generation industry. LEI's analysis relied on well-conceived and commonly accepted methods for calculating the TFP trend, while also responding to the considerations that the OEB raised in the 2017 Decision. Notably, LEI added hydroelectric generation companies to increase the peer group when compared to the LEI 2016 TFP Study. LEI also performed the analysis using both a physical approach and a monetary approach to measuring capital input, with both of LEI's approaches acknowledging that while economic depreciation is necessary for accounting and cost recovery purposes, the physical ability of a resource to generate output, which is used to measure productivity, remains relatively constant until it is retired.

LEI calculated that, for an industry peer group consisting of OPG and 20 US hydroelectric generators, using data from 2002-2023 and a physical measure of capital, the industry TFP growth over the study period averaged -0.40% per year (using the trend regression method) for 21 peers and -0.61% for 17 peers. Under the monetary approach, the TFP growth rate averaged -1.01% per year (this is for the slightly smaller industry peer group of 17 peers). The comparison of these results is shown previously in Figure 33 on page 55. The main takeaway from these results is that regardless of the specific approach used in the estimation of the capital input quantity, the outputs have generally been growing more slowly than inputs, resulting in a negative TFP trend for the industry.

In comparison, the LEI 2016 TFP Study had reported a -1.18% industry average TFP growth rate for the 2002-2014 timeframe, using the physical approach for measuring capital input and the 'trend regression' method of calculating the average annual growth rate. The updated TFP results are slightly less negative than the previous TFP study, mostly reflecting a recent trend observed among the US peers of higher generation output in the additional years of the study (2015-2023), as well as the addition of WAPA, who, because of its portfolio size and experienced hydrology, also contributes to a less negative TFP growth rate.

Negative TFP growth results are not surprising and are to be expected. This observation of a negative TFP does not mean that hydroelectric companies are inefficient. Rather, the negative TFP growth rate is a result of the fact that production or output growth is generally not expected over the life of a hydroelectric plant (unlike the output growth that network businesses experience as they add more customers). For a hydroelectric generator, although output is generally not growing, the quantity of inputs does increase over the lifetime of a hydroelectric plant in order to maintain the operational capability at design levels.

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8 Appendix A: List of acronyms

AWE	Average Weekly Earnings
BEA	Bureau of Economic Analysis
BLS	Bureau of Labor Statistics
BPA	Bonneville Power Administration
Chelan	Chelan County Public Utility District
DEA	Data Envelopment Analysis
EIA	Energy Information Administration
EUCG	Electric Utility Cost Group
FERC	Federal Energy Regulatory Commission
FF1	FERC Form 1
FDD	Final Domestic Demand
GDP	Gross Domestic Product
GRC	Gross Revenue Charge
HOEP	Hourly Ontario Energy Price
ICE	Intercontinental Exchange
IESO	Independent Electricity System Operator
IR	Incentive Ratemaking
IRM	Incentive Rate Mechanisms
IRS	Internal Revenue Service
ISO	Independent System Operator
LADWP	Los Angeles Department of Water and Power
LEI	London Economics International LLC
MCR	Maximum Continuous Rating
MACRS	Modified Accelerated Cost Recovery System
MW	Megawatt
MWh	Megawatt hour
NERC	North American Electric Reliability Corporation
NYPA	New York Power Authority
OEB	Ontario Energy Board
OECD	Organisation for Economic Co-operation and Development
OHS	One Hoss Shay
O&M	Operations and Maintenance
OM&A	Operations, Maintenance, and Administration
OPG	Ontario Power Generation
PEG	Pacific Economics Group
PG&E	Pacific Gas & Electric
PFP	Partial Factor Productivity
PI	Price Index
PJM	Pennsylvania, Jersey, Maryland Power Pool
PPP	Purchasing Power Parity
RRF	Renewed Regulatory Framework
RTO	Regional Transmission Organization
SEPA	Southeastern Power Administration
SERC	Southeastern Electric Reliability Council

SFA	Stochastic Frontier Analysis
StatCan	Statistics Canada
SWPA	Southwestern Power Administration
TFP	Total Factor Productivity
TVA	Tennessee Valley Authority
US	United States
WAPA	Western Area Power Administration

9 Appendix B: Implicit rental price formula

The implicit rental price formula has the following mathematical representation:

$$PK_t = \frac{1-uz}{1-u}(r-i)\left[1-\left(\frac{1+i}{1+r}\right)^{s}\right]^{-1} BLS_PPI_{t-1}$$

The variable u represents the corporate income tax rate, the variable z represents the present value of tax depreciation charges on one dollar of investment, the variable r represents the forward-looking cost of capital, and the variable i represents the forward-looking inflation rate. The service life for the whole asset base (82 years) is also used in the implicit rental price formula.[86]

Corporate income tax rate (u): For peers operating across multiple states, LEI determined the applicable tax rate (u) for each utility by computing the annual average corporate income tax rate weighted by installed hydro capacity in each applicable state. For peers operating in a single state, LEI simply used the top corporate income tax bracket in that state.

Present value of tax depreciation charges (z): This represents the present value of future depreciation on new investment. This component is used because depreciation for tax purposes typically takes place over a much shorter period than what is allowed for ratemaking purposes. z is a function of the tax depreciation method used,[87] the service life, and the weighted average cost of capital ("WACC"). LEI applied the sum of years' digits method,[88] and the resulting value for this study was 0.643. z is summarized as follows:

$$z = \frac{2}{RT}\left[1-\left[\frac{(1+R)}{R(T+1)}\right]\left[1-\left(\frac{1}{(1+R)}\right)^{T+1}\right]\right]$$

Forward-looking WACC (r) and inflation rate (i): A common method is to assume that investors' forward-looking real rate of return (cost of capital less the inflation rate) is constant through time. This method produces a relatively stable input price series (in contrast to using just the current years' WACC and inflation rates). For US peers, the resulting average WACC of 6.90%[89] and

[86] LEI estimated OPG's average service life for the entire power plant complex by computing the average service life of all hydroelectric assets prorated by 2024 book value. OPG's average service life for the whole asset base was estimated to be 82 years.

[87] The depreciation life for tax purposes was assumed to be 20 years over 2002-2023 based on the General Depreciation System recovery period for electric utility hydraulic production plants, found in the Internal Revenue Service's ("IRS") 2024 Modified Accelerated Cost Recovery System ("MACRS") publication.

[88] Under the sum of years' digits depreciation method, the annual depreciation amount is weighted toward the earlier years of an asset's life by applying fractions based on the reverse order of the asset's remaining life over the sum of the years' digits. This approach increases early-period tax savings relative to straight-line depreciation, enhancing the present value of tax deductions. Source: L. Macdonald Wakeman, "Optimal Tax Depreciation," Journal of Accounting and Economics, Vol. 2, 1980, pp. 213–237.

[89] In calculating the WACC, the average cost of debt is based on the average Moody's seasoned Baa bond yield, published by the Federal Reserve Bank of St. Louis. Source: Moody's Seasoned AAA Corporate Bond Yield.

expected long-term inflation rate of 1.88%[90] (over the study timeframe) was then used in the implicit rental price formula for all US hydroelectric companies. For OPG, the resulting average WACC was 6.17%,[91] whereas the expected long-term inflation for Canada was 1.58%.[92]

https://fred.stlouisfed.org/series/Baa. The cost of equity is based on the average approved ROEs of the hydroelectric companies that were available from the 16 US peers. Source: Reported ROEs in S&P Capital IQ. The debt/equity ratio was assumed to be 51.1%, based on an average of reported debt/equity ratios for electric utilities from 2002-2023. Source: S&P Capital IQ, Rate Case History. Average Rate of Return on Equity.

[90] The long-term expected inflation rate is calculated using the Fisher Ideal equation based on rates of the 10-Year U.S. Treasury bonds and the 10-Year U.S. Treasury Inflation-Protected Securities ("TIPS") from 2002-2023. Source: U.S. Treasury, Daily Treasury Yield Curves 10-YR. https://www.treasury.gov/resource-center/data-chart-center/interest-rates/pages/textview.aspx?data=yield. Bureau of the Fiscal Service. https://www.treasurydirect.gov/instit/annceresult/tipscpi/tipscpi.htm.

[91] To calculate the OPG-specific WACC, LEI calculated the average WACC for OPG's hydroelectric generating facilities from 2002-2023. For 2005-2023, LEI used the OEB's approved parameters for debt/equity ratio, cost of debt, and cost of equity. For 2002-2004, LEI used OPG's financial statements to estimate parameters such as debt/equity ratio and cost of debt; to estimate the ROE for this period, LEI used the approved ROE set by the OEB in RP-1999-034 – even though it is an allowed ROE set explicitly for distributors, LEI believes this is a reasonable assumption as allowed ROEs for distributors and generators are still the same to this day.

[92] For Canada, the long-term expected inflation rate is calculated using the Fisher Ideal equation based on rates of the 10-Year GC benchmark bonds and Canadian real return bonds from 2002-2023. Source: Bank of Canada. Selected bond yields. https://www.bankofcanada.ca/rates/interest-rates/canadian-bonds.

10 Appendix C: Lessons learned and challenges through review of economic literature on productivity studies

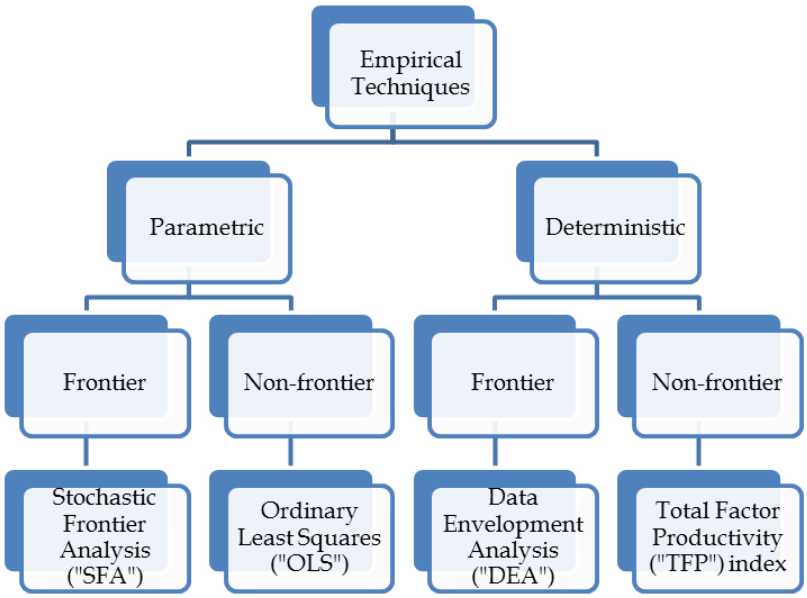
As part of the research phase of this study, LEI reviewed several previous studies that analyzed productivity of generation, distribution, transmission sectors, or the electricity sector as a whole.[93] For each study, LEI summarized the data used, method employed, TFP composition (inputs and outputs), and study conclusions. This section presents the key findings of LEI's review.

10.1.1 Methods for measuring productivity

There are various methods for performing a TFP study: stochastic frontier analysis ("SFA"), data envelopment analysis ("DEA"), and TFP indexes. They can be broadly categorized into deterministic methodologies, which "calculate" TFP, and econometric methodologies (which are also known as parametric methods), which "estimate" TFP.

TFP study methods can also be categorized into frontier and non-frontier. Frontier methods assume that production units do not fully use existing technology. These methods are able to break productivity growth down into technical change and efficiency change; technology changes can push the frontier upwards, while efficiency changes are productivity improvements, given the same technology. On the other hand, non-frontier methods assume that production is always efficient, and equates the potential level of production at each moment in time. These methods do not separately estimate technical change and efficiency change.

Figure 35. Categories of methods used in productivity studies



[93] The LEI 2016 TFP Study included a summary of the existing economic literature on TFP measurement in the electricity sector. To LEI's knowledge, no new empirical TFP studies specific to electricity generation have been published in the regulatory context since then.

Figure 36. Common indexing techniques

Laspeyres Index:

- *Named for French economist Etienne Laspeyres*
- *Indexation method in which all input and output values are weighted at base year prices to ensure consistent price comparisons*
- *Becomes an increasingly inappropriate methodology as the time interval and/or price variability increases*

Paasche Index:

- *Named for German economist Hermann Paasche*
- *Indexation method similar to the Laspeyres method, except that all input and outputs are valued at their end of period prices to ensure price consistency*
- *Also becomes increasingly inappropriate as the time interval increases and/or the price variability increases*

Fisher Index:

- *Named for American Economist Irving Fisher*
- *Attempts to minimize the inaccuracies inherent in the Paasche and Laspeyres methods of price indexation by weighting all input and output prices by the geometric mean of base year and end of period prices*
- *The geometric mean involves the square root of the product of base year and end of period prices*
- *In a TFP period scenario, a Fisher Indexation TFP calculation can also be calculated as the geometric mean of the TFP calculations resulting from the Paasche and Laspeyres indexation techniques*

Törnqvist index:

- *Attributed to Finnish economist Leo Törnqvist and is commonly used in TFP studies*
- *Approximates the Fisher indexation method, whereby indexes are formed by each component's weighted geometric mean, relative to a base year, in which weights are equal to the components average cost share*
- *Typically analyzed in logarithmic format*

Malmquist Index:

- *Initially introduced in: "Multilateral Comparisons of Output, Input and Productivity Using Superlative Index Numbers", by Douglas W. Caves, Laurits R. Christensen and W. Erwin Diewert in 1982, but named for Swedish economist Sten Malmquist*
- *Parametric method that uses techniques similar to DEA to construct an efficient frontier which changes annually, thus measuring productivity relative to the previous year*
- *Classifies efficiency into technical change and efficiency change aspects*
- *One advantage is that it does not require price or cost information so is often in used when there are data limitations*

First introduced by Charnes et al in 1978, DEA is a linear programming technique which identifies best practice within a sample by fitting a frontier over the top of the data points; relative efficiencies are measured from less efficient firms with respect to the frontier. DEA is a method which is more popular in academic studies, given the amount of detail it can provide. It is often used with a Malmquist index, which measures productivity change between two points in time.

One of the most important benefits is that DEA is able to decompose cost efficiency into component parts, breaking down allocative and technical efficiencies. Technical efficiencies can be in turn decomposed into scale and pure technical efficiencies. This allows researchers to identify the best role models and make recommendations on improving efficiency. It is also not required to specify the functional form of the production relationship, and depending on which version of DEA is used, it is often not necessary to specify prices or weights for inputs and

outputs. Specifying weights is often one of the more challenging aspects of measuring productivity.[94] Finally, DEA can easily deal with multiple inputs and outputs.

In terms of weaknesses, DEA is particularly sensitive to measurement error for frontier firms, since DEA uses these firms to derive efficiency. DEA also requires a large dataset, where a rough rule of thumb is that the number of observations needs to be at least three times the sum of the number of outputs and inputs to get worthwhile results. Finally, DEA has not typically been used to determine X-factors in regulatory proceedings, given its complexity, being regarded as a 'black box', and poor experiences with DEA by regulators.[95]

In contrast, TFP index methods measure the ratio of all outputs to inputs, where input and output indexes are constructed using both quantities and prices of outputs and inputs. Traditionally, it can be used to compare rates of change of productivity but not absolute levels, though more recent developments have overcome this shortcoming. Benefits are that it is a relatively simple and robust technique, and thus it is often used for regulatory proceedings. As well, index number methods can incorporate many inputs and outputs with few observations. However, it requires values for all outputs and inputs. As well, it is not able to break down efficiencies into its component parts, such as scale efficiency or technical efficiency.

SFA is an econometric method which recognizes that some of the difference between a firm's actual costs and the line of best fit are due to random events rather than inefficiency. Like DEA, SFA is also able to break down efficiencies into its component parts, such as scale efficiency or technical efficiency. Finally, it is able to separate the error term in the stochastic production function into two elements – genuine inefficiency and random fluctuations.

In terms of disadvantages, SFA is an econometric method, which is generally more complex, difficult to communicate, and requires significant data. It is therefore not typically used by experts performing productivity studies for ratemaking or other regulatory purposes. Rather, it is more often used in academic studies.[96] Furthermore, it requires specification of a production or cost function, and although it recognizes randomness in the line of best fit, if there are in fact no measurement errors in the sample, some inefficiency would be regarded as noise.

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[94] The cost efficiency version of DEA requires specification of output and input weights in the DEA data set.

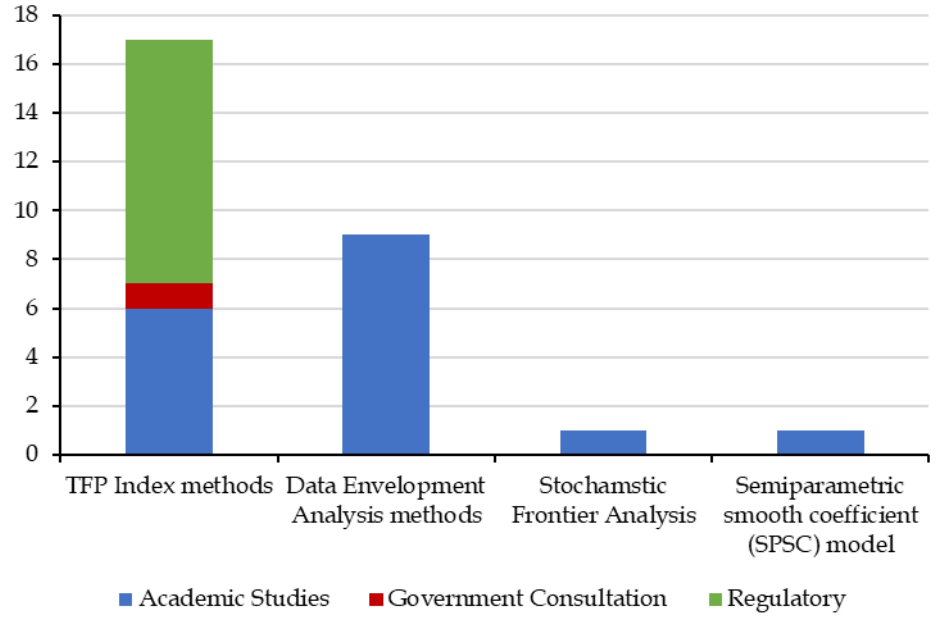
[95] Some academic studies have noted that the use of DEA in regulatory benchmarking can create opportunities for strategic behaviour by regulated firms. For example, in Norway, several electricity distribution companies engaged in mergers that were not necessarily driven by operational efficiencies but were rather aimed at improving their relative efficiency scores under DEA-based regulation. By altering their organizational structure or scale, firms were able to reposition themselves in the efficiency frontier, thereby receiving more favourable regulatory treatment. This type of regulatory gaming highlights the importance of carefully designing benchmarking models to mitigate manipulation and ensure fair and accurate assessments of performance. Source: P. J. Agrell, P. Bogetoft and T. E. Grammeltvedt. *The efficiency of the regulation for horizontal mergers among electricity distribution operators in Norway*. 2015.

[96] OECD. *Measuring Productivity: Measurement of aggregate and industry-level productivity growth*. 2001.

10.1.2 Selecting a TFP method

In order to choose the optimal TFP method, LEI reviewed 26 TFP studies on electricity generation companies, as well as transmission and distribution utilities. These included 15 academic studies, 1 government consultation, and 10 regulatory productivity studies.[97]

Figure 37. Productivity study methodologies reviewed



While DEA and TFP methods are both commonly used for the electricity industry, DEA is less practical from a regulatory perspective, given its primary advantage is limited in value for setting an X-factor, it requires more data, and it is difficult to communicate. The indexing method, due to its transparency and relative simplicity, is most often the method of choice for productivity studies performed for regulatory purposes. Furthermore, in Ontario, the OEB has used the index method for incentive regulation of distributors. For these reasons, LEI believes the index method is the optimal choice for measuring TFP in this study.

10.1.3 Outputs used in TFP studies

Of the 26 TFP studies reviewed by LEI, 18 were focused on electricity generation companies. For these 18 studies, LEI assessed what outputs were commonly used – see Figure 38 and Figure 39 below. The most common output was energy generation in MWh, as that is what is being produced by every power plant. LEI also notes that generation data is readily available and can be consistently measured across a peer group. In two fossil fuel studies, pollutants were captured as a negative output; however, this is not applicable to hydroelectric plants.

[97] Note that some studies used multiple methods.

Figure 38. Outputs used in generation productivity studies

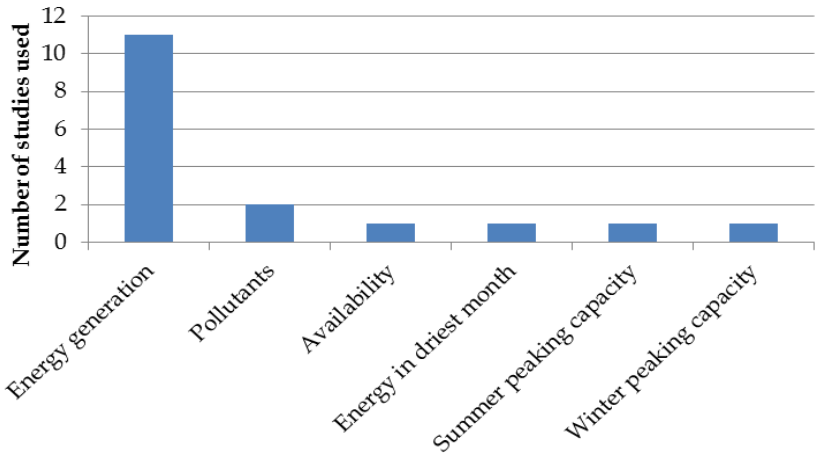


Figure 39. Example of outputs used in generation productivity studies

Outputs	Examples
Power Produced	• Generation (MWh) • Output in specific periods (e.g., to support resource adequacy)
Ancillary Services	• Reactive support/voltage control • Automatic Generation Control • Black start • Reliability must-run
Reliability	• Availability • Forced outage rates
Other Services	• Sale of ancillary services • Water management • Added flexibility to system

10.1.4 Inputs used in TFP studies

For the 18 TFP studies that were focused on electricity generation companies, LEI also assessed what inputs were commonly used – see Figure 40 and Figure 41 below. The most common input observed for generation-related productivity studies was capacity (as a measure of capital). Specifically, capacity in MW is very commonly used as a proxy measure. Capital can also be measured using replacement cost, but is much less common – in fact, nearly every study used capacity as a measure of capital.

Figure 40. Inputs used in generation productivity studies

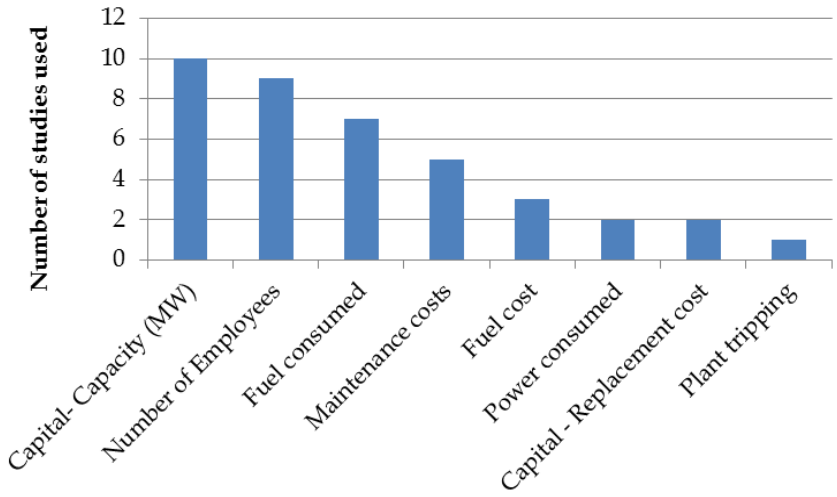


Figure 41. Example of inputs used in generation productivity studies

Inputs	Examples
Capital	• Physical measure: Plant Capacity (MW) • Monetary measure: Depreciated or replacement value of capital stock
Operations and Maintenance	• Operations and Maintenance (O&M) without labour costs • Operations and Maintenance (O&M) with labour costs
Labour Employed	• Number of Employees • Wages ($)
Other Costs	• Power consumed • Environment and regulatory

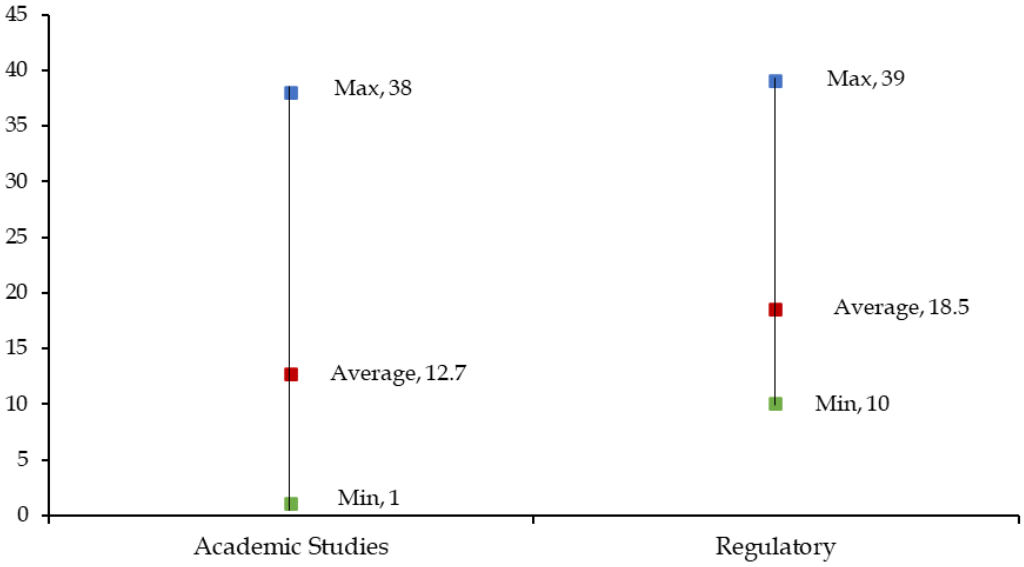
The second most common input was number of employees, which captures the labour involved in power production. LEI decided against using number of employees in favour of O&M costs due to data limitations (employee figures were not readily available for all US peers). Labour costs were captured already in O&M costs and also in the input price indices. Another important input is fuel, whether it is captured by fuel consumed (often in joules), power consumed (in MWh), or in terms of annual fuel costs. However, this method is more important when looking at thermal generation plants and thus is not relevant in the context of a hydroelectric TFP study.

10.1.5 Length of TFP studies

LEI also reviewed the 26 TFP studies to aid in the determination of an appropriate period of study. Figure 42 below shows the range of study period timeframes observed. It is clear from the studies reviewed that a set of data which spans 10 years or more is common for productivity studies. Although some academic studies have very short study periods, this can often be attributed to the purpose of the study, which is to make conclusions about the productivity

method, rather than making a conclusion about productivity trends (which must be backed by a sufficiently large dataset). This can be corroborated by the fact that regulatory studies all used a study period of over 10 years.

Figure 42. Length of reviewed productivity studies



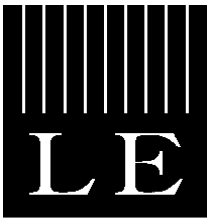
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BENCHMARKING THE COSTS OF HYDROELECTRIC GENERATION COMPANIES IN NORTH AMERICA

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This report was prepared by London Economics International LLC for Ontario Power Generation for the sole purpose of the Ontario Energy Board Rate Application. It should not be used or relied upon for any other purpose.

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1 Executive summary

Since 2017, Ontario Power Generation ("OPG") has been under an I-X incentive ratemaking ("IR") regime for setting payment amounts for its prescribed hydroelectric assets.[1] OPG is now filing its second-generation hydroelectric payment amounts ("HPA") application with the Ontario Energy Board ("OEB") and has engaged London Economics International LLC ("LEI") to prepare a new hydroelectric generation industry total factor productivity ("TFP") study,[2] as well as to perform an econometrics-based total cost benchmarking ("TCB") study to evaluate OPG's efficiency compared to other hydroelectric generation companies in North America. The focus of this report is LEI's TCB analysis. As described below, this study shows that OPG is a cost-efficient hydroelectric generator.

1.1 Overview of the use of econometric techniques for total cost benchmarking

Total cost benchmarking is a way to evaluate the performance of an individual firm by comparing its performance to that of other firms in the same industry. As noted in a recent report funded in part by the OEB, "*TCB is a sophisticated approach that employs econometric analysis to compare an organization's total costs against those of other firms. This method utilizes statistical models to analyze the relationship between total costs and various influencing factors, such as scale of operations, input prices, and business conditions across different organizations. By integrating econometric techniques, this benchmarking approach allows for a more nuanced understanding of cost drivers and efficiencies. It adjusts for differences in company size, output levels, and other variables that affect costs, providing a clearer comparison of inherent cost efficiencies or inefficiencies among firms*."[3]

In LEI's professional judgement, an econometrics-based TCB analysis, if the data allows, is preferable to a simpler unit cost analysis. A unit cost analysis would simply divide total expenditures by plant size in megawatts ("MW") and thus cannot account for (or, similarly, control for) differences in the price of labour, the number of units, or any other factors that may impact costs and may differ across operators. In contrast, the econometric process estimates the statistical relationship between a dependent variable and one or more independent (explanatory) variables. A dependent variable "depends" on the value of another variable or variables. For example, total operations, maintenance and administration ("OM&A") spending of an owner on its power plants will depend on several explanatory variables (which may also be referred to as "drivers" or "factors"). At the same time, the econometric methodology can isolate the impact of plant size (for example) from the impact of other factors, such as input prices (for example) on

[1] OEB. *Decision and Order EB-2016-0152 - Ontario Power Generation Inc. Application for payment amounts for the period from January 1, 2017 to December 31, 2021.* December 28, 2017.

[2] In February 2016, LEI prepared a TFP study (referred to herein as the "LEI 2016 TFP Study") which was filed with the OEB in conjunction with OPG's first-generation HPA application (EB-2016-0152). LEI's new TFP study (prepared for OPG's second-generation HPA application), titled "Empirical Analysis of Total Factor Productivity Trends in the North American Hydroelectric Generation Industry" and covering the 2002-2023 period, has been filed as a separate report.

[3] Yatchew, Adonis, Frederik Dufour, Erik Harris-Uldall, Shuofei Li, Michael Scafe, Leb Jenric Valencia, Lucy Wolff. *Review of Total Cost Benchmarking Methodology for Electricity Distributors.* November 12, 2024. P. 17. The report was supported by the OEB and the University of Toronto Climate Positive Energy Initiative.

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total OM&A expenditures. Controlling for these independent variables is important for arriving at a measure of relative efficiency that can be interpreted as the result of contemporaneous business decisions by the operator (owner of the plant).

1.2 LEI's approach to TCB

In this TCB study, LEI included operations, maintenance, and administration expenditures, as well as the expenditures related to a subset of capital spending (sustaining capital).[4] LEI performed the TCB study using actual (historical) data from a group of 13 North American hydroelectric power plant operators and 253 plants, including OPG's regulated plants, to estimate the average relationship between costs and factors that contribute to those costs. The technique LEI used also allows for the ranking of operators by their efficiency relative to one another after examining averages and controlling for a variety of factors.

LEI's TCB study relied on data from the Electric Utility Cost Group ("EUCG") Hydroelectric Productivity Committee ("HPC") database, which covers hundreds of hydroelectric power plants owned by over a dozen operators[5] located across the United States and Canada.[6] Although the EUCG HPC dataset is confidential, LEI can confirm that aside from OPG, one other Canadian entity was included in the TCB study. The EUCG dataset collects granular performance and cost information at the plant level from its members. Rigorous policies and guidelines for data submission by EUCG members and methodical collection and data validation practices ensure that the data is consistent across operators, as is required for the purposes of high-quality benchmarking.[7]

LEI used four years of data (2020-2023), for a total of 1,012 observations. LEI believes that use of four years of data strikes an appropriate balance between two competing objectives: four years captures sufficiently recent information to ensure relevance, while also providing enough data

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[4] For reasons discussed later in the report, LEI excluded other categories of capital expenditures. However, LEI's methodology is consistent with a typical TCB approach such as described in the report entitled *Review of Total Cost Benchmarking Methodology for Electricity Distributors* prepared for the OEB by Adonis Yatchew, Frederik Dufour, Erik Harris-Uldall, Shuofei Li, Michael Scafe, Leb Jenric Valencia, and Lucy Wolff, November 12, 2024.

[5] Including regional subdivisions of US federal entities.

[6] EUCG provided the confidential HPC dataset to LEI on an "unblinded" basis, with the names of the power plants and operators/owners visible. This data was provided under a non-disclosure agreement between EUCG and LEI.

[7] EUCG describes itself as a "*nonprofit organization formed in 1973 by several electric utilities to track the rising cost of nuclear power plant construction. Later, the focus shifted to comparing operating and maintenance costs. In 1993, an interest group was developed to include hydroelectric power plants, leading to the formation of the Hydroelectric Productivity Committee (HPC) within the EUCG. This organization provides a low-expense solution to cost and performance benchmarking.*" Furthermore, EUCG states: "*In 2005, the HPC employed a web-based SQL database for storing and tracking the cost and performance data elements. A revised User Guide and Data Catalog (Electric Utility Cost Group, 2023) was issued that provided member utility companies with specific instructions regarding the composition of each cost or performance data element. These instructions ensure data consistency, which is critical to benchmarking. An annual data review meeting is conducted as part of the data validation process before the database is posted on the HPC website for use by HPC members.*" (Source: EUCG. *2023 Annual Cost and Performance Report: Hydroelectric Productivity Committee*)

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points to support a statistically robust analysis (economic models benefit from having a sufficiently large number of observations, as this improves the precision and reliability of the statistical estimates).

EUCG HPC members submit their annual performance and expenditure data to the HPC database every year, following the reporting and classification instructions provided in the HPC Data Guide. Although EUCG members may periodically change the set of plants for which they choose to submit data, LEI ensured that for the purposes of this benchmarking study, we relied on the most recent four years of data that have a consistent representation of power plants of varying sizes, vintages, and equipment. The data used in this TCB study encompasses the size range of OPG's prescribed hydroelectric fleet (which ranges from 0.9 MW to 1,499 MW). The group of plants used in LEI's economic models have installed capacities ranging from 0.5 MW to 4,215 MW.

LEI developed two economic TCB models: an OM&A model and an OM&A plus sustaining capital spending ("OM&A + SC") model. The OM&A model reflects the annual operations, maintenance, and administration expenditures, including non-reoccurring project-related O&M expenses. The OM&A expenses in the EUCG HPC database include expenses related to operations (for facilities operations and generation planning and integration), maintenance (for powerhouse and non-powerhouse), and administration expenses (direct and indirect).[8] This level of coverage captures all aspects of OM&A expenses that can be compared across owners.

In the OEB's 2017 Decision in response to OPG's first-generation HPA application, the OEB commented that with regards to future benchmarking efforts, it "*expects OPG to continue to examine whether additional costs should be benchmarked for the purposes of future stretch factors*."[9] For this reason, LEI created the OM&A + SC model in addition to the OM&A model. The OM&A + SC model combines OM&A expenditures and annual capital expenditures for sustaining plant capability. According to EUCG HPC's definition, capital expenditures for sustaining capability are driven by the need to maintain existing assets in good running condition.[10] They usually include equipment replacement and may or may not include technological improvements that extend equipment useful life. However, LEI excluded capital investments associated with improvements and additions to plant generation capacity, as these depend on where a company is within its broader investment cycle, occur irregularly, and are typically large in terms of dollars spent. Including these costs in an econometric analysis over a timeframe of four years could distort comparisons, given that not all companies would have faced similar capacity-improvement capital spending during the study period.

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[8] According to the EUCG HPC Database Data Guide and Reporting Instructions (2024), whether an expense belongs to the "direct" or "indirect" category is determined by the driver (type of work). Specifically, expenses that are driven by plant activities are typically categorized as direct costs, and expenses incurred by activities for managing the hydroelectric business unit are generally categorized as indirect costs.

[9] OEB. *Decision and Order (EB-2016-0152): OPG's application for payment amounts for the period from January 1, 2017 to December 31, 2021*. December 28, 2017. P. 129-130.

[10] EUCG. *Data Guide and Reporting Instructions.* Hydroelectric Productivity Committee. January 31, 2024. P. 56.

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To benchmark OPG's efficiency compared to other hydroelectric generating companies in North America, LEI conducted an econometrics-based analysis to generate an estimate of the average relationship between the total cost of a hydroelectric plant and explanatory factors. The analysis estimates the degree to which each factor contributes to plant-level expenditures.

In addition to establishing this average relationship, the model used here includes independent variables which reflect ownership, by tracking the impact of an effect specific to each operating entity. This is referred to as a "fixed effect" ("FE"), because it does not vary over time and tracks only the impact on cost from a plant being owned by OPG or any other operator/owner. In other words, the fixed effect in this benchmarking study measures the impact on the cost of a generating plant associated with ownership (i.e., whether a specific plant is owned by one entity versus another). Therefore, the size and sign of the firm-specific effect measures the relative efficiency of an owning entity. The more positive an entity's fixed effect is, the higher its OM&A spending or OM&A + SC spending (all other factors held constant – in other words, controlled for), and therefore the less cost-efficient the company is estimated to be relative to the other entities. LEI set up the economic models so that OPG's fixed effect is equal to zero. Therefore, the econometric estimation of a positive FE implies higher expenditures than OPG (all else equal), so less cost-efficiency than OPG. Negative FE estimates imply lower expenditures than OPG (all else equal), therefore such entities are more cost-efficient than OPG. In this way, the econometric analysis assesses the relative efficiency level of each company in the dataset.

1.3 Summary of results

LEI's TCB study provides empirically derived information to aid the OEB in calibrating the X factor in the "I-X" mechanism with addition of a stretch factor. Based on the benchmarking analysis presented in this report, which relied on information from 253 hydroelectric plants owned and operated by 13 different entities in Canada and the United States, LEI concludes that OPG is a significantly cost-efficient hydroelectric generator. OPG's OM&A costs were 42% lower than the other entities' costs when controlling for plant size, capital prices, labour prices, and several other factors. As a result, OPG ranked 3rd in the OM&A model (first quintile). OPG's OM&A + SC costs were 15% lower than the other entities' costs when controlling for the same factors. As a result, OPG ranked 4th in the OM&A + SC model (second quintile). The range of efficiencies implied by LEI's results is wide, but such ranges are not uncommon for the results of efficiency studies.[11]

Based on this assessment, LEI recommends a corresponding stretch factor in the range of 0% to 0.15%, in alignment with OEB's established cohort groupings (see Figure 1).

[11] See, for example, "Empirical Research in Support of Incentive Rate Setting in Ontario: Report to The Ontario Energy Board." Pacific Economics Group Research, LLC. May 2013; "Statistical Research for Public Service Company of Colorado's Multiyear Rate Plan." Pacific Economics Group Research, LLC. May 2017; and "Benchmarking the Total Cost of NSTAR Gas Company." London Economics International LLC. Massachusetts DPU 19-120, November 2019.

Figure 1. OEB's stretch factor values by cohort

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

Note: OEB's reference to "predicted costs" in the table above is equivalent to "expected cost" referred to based on LEI's methodology, as described in this report.

Source: OEB. *Report of the Board (EB-2010-0379): Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors.* November 21, 2013. P. 21.

1.4 Structure of this report

This report is structured as follows: Section 2 explains what an econometrics-based benchmarking study is and how it is typically used in IR regulatory proceedings. Section 3 provides a high-level overview of LEI's econometric methodology. Section 4 discusses the results of the study and OPG's relative efficiency rankings. Appendix A in Section 5 provides background on other econometric benchmarking approaches which LEI considered but rejected as less appropriate for the current study. Appendix B in Section 6 provides a list of acronyms used in this report.

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2 The purpose of total cost benchmarking

The purpose of total cost benchmarking is to compare the performance of an individual firm to the performance of other individual firms (referred to as "relative efficiency"). TCB studies provide empirical evidence that can be used to inform a regulator's expectations for further efficiency improvements for a regulated company. By identifying the relative cost-efficiency of a regulated firm, a total cost benchmarking study can help the regulator calibrate the IR mechanism, which in the case of OPG and OEB's regulations would be encapsulated in the I-X formula. The base productivity component of the X factor reflects the change in efficiency over time for the whole industry in question. It is typically measured using estimates of the long-run trend in total factor productivity growth for the regulated industry relative to the overall macro economy. In addition to the base productivity component of the X factor, a regulator may add a stretch factor for an individual entity, to reflect the incremental productivity gains that the regulator expects the individual firm to achieve compared to the industry average.

The results of a TCB study inform the setting of the stretch factor. A regulator generally sets stretch factors lower for firms that are already relatively more efficient, and higher for firms that are relatively less efficient.[12] This is because a firm which is less efficient than average might be expected to improve faster than the industry average, as it may have more low-hanging fruit for efficiency improvements. A firm which is already more efficient than average may have fewer opportunities for improvement, as it may have already taken advantage of better technologies and management techniques. Eventually, firms that have exhausted all "catch-up" opportunities will be constrained by the rate of industry average TFP growth. This phenomenon is referred to as the convergence effect (see Figure 2).[13]

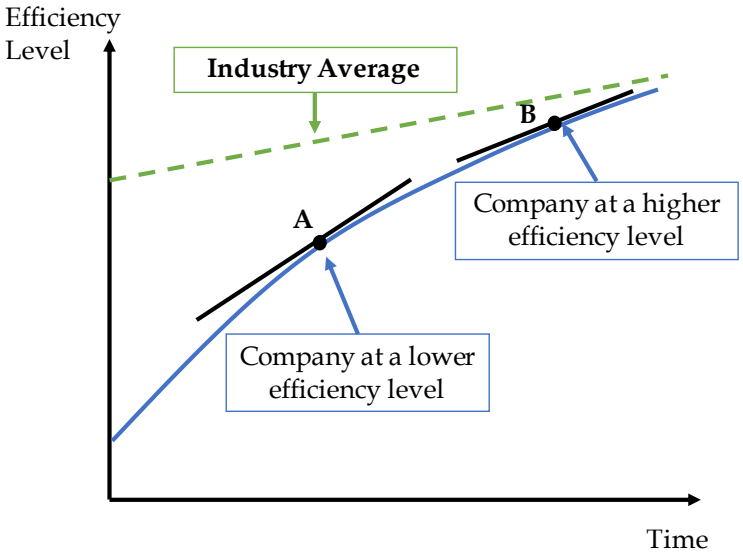
The potential for such individual efficiency improvements is often determined with reference to a TCB study, such as the one performed by LEI and documented in this report. The benchmarking process measures relative efficiency by determining whether and by how much the firm is above or below the industry average level of cost productivity at a recent point in time. This comparison helps to determine the incentive that the regulator would impose to improve the firm's efficiency and close the gap compared to the industry average. For example, a firm in position A in Figure 2 would probably face a larger incentive (i.e., a higher stretch factor) imposed by the regulator to catch up to the industry average than if it were in position B, since position A is much less efficient than position B, and has a larger gap to the industry average.

[12] OEB. *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*. July 14, 2008.

[13] Schmidt, Michael, *Performance-Based Ratemaking: Theory and Practice*. USA: Public Utilities Reports, Inc., 2000; Cambridge Economic Policy Associates Ltd, Productivity Improvements in Distribution Network Operators Final Report, November 2003; Roberts, B.F, *Performance-Based Regulation: Efficiency and the Measurement of Productivity Offset*, ESC Electric Utility Analysis Report 95-1.

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Figure 2. Illustration of the convergence effect



Note: The pace of improvement over time for an individual firm is not a straight line but a curve line. This is because the convergence effect slows the improvement of efficiency over time. The black lines tangent to the blue curve represent the slope, or rate of change of efficiency over time, at position A (lower efficiency) and position B (higher efficiency).

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3 Total cost benchmarking using econometrics

Econometrics-based benchmarking is a well-established approach for comparing firms based on their expenditures and outputs. It has been presented to regulators in many rate filing submissions in various jurisdictions and has been accepted for use in regulation of electric and gas distribution utilities in Canadian provinces (Ontario and Alberta), in jurisdictions in the United States, as well as in Australia, New Zealand, and the United Kingdom.

Econometric analysis relies on calculating the average (or "mean") value for a feature such as plant size and comparing how an individual observation in the data (for example, a single hydroelectric plant in a single year) compares to the average size of all the hydroelectric plants across all the years in the data. Econometric analysis then tests for correlations across such differences in means. For example, it tests whether the difference from the mean size of a plant is correlated with the difference from the mean OM&A expenditures for a plant.

These differences are reflected in a statistical relationship between a dependent variable and one or more independent (explanatory) variables. A dependent variable "depends" on the value of another variable or variables. For example, the magnitude of total OM&A expenditures will depend on, among other things, the size of the power plant (its generating capacity). A plant with higher installed capacity will typically require more staff to operate and maintain the facility, increasing OM&A expenditures. Larger plants may also require more equipment (more turbines), increasing sustaining capital spending. Therefore, LEI uses OM&A expenditures (or OM&A plus sustaining capital spending, depending on the model) as the dependent variable. An independent variable explains the level of the dependent variable. For example, the total OM&A expenditures for a hydroelectric plant can be explained by its size (capacity), the price of labour and capital, and potentially other independent variables. These independent variables are sometimes referred to as drivers of costs, business conditions, or simply "other factors". Controlling for these independent variables is important for arriving at a measure of relative efficiency that can be interpreted as the result of business decisions by the company.

Some of these independent variables are entirely beyond managerial control, while others can be modified only with significant time and investment. For example, once a hydroelectric plant is designed and built, its energy output becomes a function of hydrological conditions, and its capacity is fixed (until the plant is refurbished or new technology can be applied to the runner). Other business drivers may only be changeable with time and additional expenditure. For example, there are specific technical reasons (including safety) that some plants have staffed control rooms, while others have remote operations; changing from one to another cannot happen overnight.

The econometric process allows one to measure how much and in what direction each of these factors impacts total expenditures, on average, for a set of observations (for example, how total expenditures are affected by labour prices for a set of power plants in a given year, or over a given number of years). The econometrics-based approach requires a sufficiently large set of standardized data to provide reliable results, which is why, if such data are not available, other benchmarking approaches are sometimes used.

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3.1 Establishing the appropriate economic model

Econometrics involves the application of statistical techniques to an economic model. Therefore, before performing econometrics, LEI defined two suitable economic models: one which describes total OM&A expenditures (in other words, OM&A expenditures as the dependent variable) and an alternative model in which total OM&A plus sustaining capital spending is the dependent variable. Thus, LEI tested two ways of examining relative efficiency: one which did not include sustaining capital spending, and only looked at OM&A, and another which included both types of spending.

3.1.1 The functional form of the economic models

LEI used a single-equation model for OM&A and an alternative single-equation model for OM&A + SC.

3.1.2 Definitions of variables used in the OM&A model and the OM&A + SC model

The dependent variable in LEI's OM&A model consists of OM&A expenses, including the following expenditure categories reported in the EUCG HPC database:[14]

- operations;
- maintenance;
- administration; and
- "project-related" O&M expenditures (non-recurring major operational expenses).

The dependent variable in LEI's OM&A + SC model includes the expense categories above plus annual capital expenditures for sustaining plant capability.

The independent variables are the same in both the OM&A model and the OM&A + SC model, except for the price drivers (the OM&A model only has one price driver; the OM&A + SC model has two price drivers), as seen in Figure 3 and described in further detail below.

[14] Operational expenses related to land and water rental were not included in the study. Also, LEI excluded environmental and regulatory expenses because some utilities in the US, due to their local legislation and/or mandates, have included certain expenses that are not directly related to plant operations and are not typically the responsibility of utilities in other jurisdictions; including these expenses would make these US companies look less cost-efficient than their peers who are not required to pay such expenses.

Figure 3. Overview of the variables used in LEI's models

Dependent variable	Independent variable	Type of variable or transformation
OM&A spending		natural log
	OM&A price index	-
	Gross capacity (MW)	natural log
	Staffed control room	binary (0 or 1)
	Two or less active units	binary (0 or 1)
OM&A+SC spending		natural log
	OM&A price index	-
	Capital price index	-
	Gross capacity (MW)	natural log
	Staffed control room	binary (0 or 1)
	Two or less active units	binary (0 or 1)

1. **OM&A price:** This is defined as the weighted average of labour price and non-labour price. LEI allocated on average 62% to labour expenses and 38% to non-labour OM&A expenses, based on the labour vs. non-labour shares of total OM&A expenses for all plants during the 2020-2023 timeframe:

    a. **Labour price:** This represents the compensation index for the utilities sector.[15] The labour price index varies by census region for US companies and by province for Canadian companies. For US plants, LEI relied on the Employer Cost Index ("ECI") for compensation reported by the US Bureau of Labor Statistics ("BLS"), and for Canadian plants, LEI relied on the Average Weekly Earnings ("AWE") reported by Statistics Canada;

    b. **Non-labour price**: LEI relied on the Gross Domestic Product Price Index ("GDP-PI") as a proxy for the non-labour price index for US plants and the Gross Domestic Product Implicit Price Index – Final Domestic Demand ("GDP-IPI FDD") for Canadian plants. This aligns with the OEB's 2017 Decision, which states that such inflation indices can be used as proxies for the non-labour price inflation.[16] The US GDP-PI is reported by the US Bureau of Economic Analysis ("BEA") and the Canadian GDP-IPI FDD is reported by Statistics Canada;

2. **Capital price (included in the OM&A + SC model only)**: LEI also used GDP-PI and GDP-IPI FDD as a proxy for the capital price index in the OM&A + SC model (for US and

[15] According to the US Bureau of Labor Statistics' definition, the utilities sector comprises establishments engaged in the provision of the following utility services: electric power, natural gas, steam supply, water supply, and sewage removal. Specifically, services associated with electric power include generation, transmission, and distribution. Similarly, Statistics Canada defines the utilities sector as comprising establishments primarily engaged in operating electric, gas, and water utilities.

[16] OEB. *Decision and Order EB-2016-0152 - Ontario Power Generation Inc. Application for payment amounts for the period from January 1, 2017 to December 31, 2021.* Section 8.1.3 and Schedule H. December 28, 2017. P. 122.

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Canadian plants, respectively). This is consistent with the OEB's 2017 Decision, which states that such inflation indices can be used as proxies for the capital price inflation;[17] and

3. **Plant capacity:** The annual capacity of a plant, measured in megawatts ("MW"). This independent variable provides a measure of the output capability of a hydroelectric generator in a given year, conditional on hydrological conditions, grid export capability, and the provision of ancillary services. Plants with a higher installed capacity likely generate more electricity and incur higher OM&A and OM&A plus sustaining capital spending, owing to increased staffing needs to operate and maintain the facility (increasing OM&A expenditures), as well as the need for more equipment, such as additional turbines (increasing sustaining capital spending), as compared to smaller plants.

LEI identified other factors that could potentially impact OM&A and OM&A + SC spending, such as the number of active units (a plant with multiple active units is likely to have higher costs than a single-unit plant) and control room staffing (staffed control rooms cost more to operate than un-staffed control rooms).[18] LEI included these factors as independent variables in the models, which allow the models to control for the impact of such variables (and the results for each of these are reported in Section 4):

1. **Control room staff**: Indicates whether a plant's control rooms are staffed and is included as a dummy variable (i.e., a variable which takes on the value of 0 or 1 in the model), with "0" representing unstaffed and "1" representing staffed control rooms. Plants with staffed control rooms might, on average, have higher OM&A expenditures and OM&A plus sustaining capital spending, due to higher labour costs; and

2. **Number of active units**: This is also included in the models as a dummy variable, with "1" representing one or two active units, and "0" representing a plant that has more than two active units.[19] Plants with more than two active units might, on average, have higher OM&A expenditures and OM&A plus sustaining capital spending, due to increased staffing needs and the need for more equipment.

Exogenous changes over time, especially if the study covers a long period of time, could also impact costs. LEI tracked this using a time-trend variable, which is standard practice in econometric modelling.

Finally, LEI included a dummy variable for each reporting entity, which tracks the fixed effects. This allows the econometric models to capture the impact of an entity's ownership on OM&A

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[17] Ibid.

[18] Notably, similar to LEI's study, EUCG's 2023 Annual Cost and Performance Report also controls for plant capacity and number of units in its benchmarking analysis. EUCG notes: "*Since plant capacity and number of units are out of management control, adjusting for these factors reduces their effects in benchmarking the performance of different plants*." (Source: EUCG. *2023 Annual Cost and Performance Report: Hydroelectric Productivity Committee.* P. ix)

[19] LEI selected two units as the threshold because approximately 50% of plants included in LEI's analysis have one or two active units, while the other 50% have more than two active units.

expenditures and OM&A plus sustaining capital spending, as further explained in Section 3.4 below.

LEI tested several other independent variables, but they were ultimately excluded as they were found not to be statistically significant for the study timeframe and group of power plants.

3.2 Overview of the data

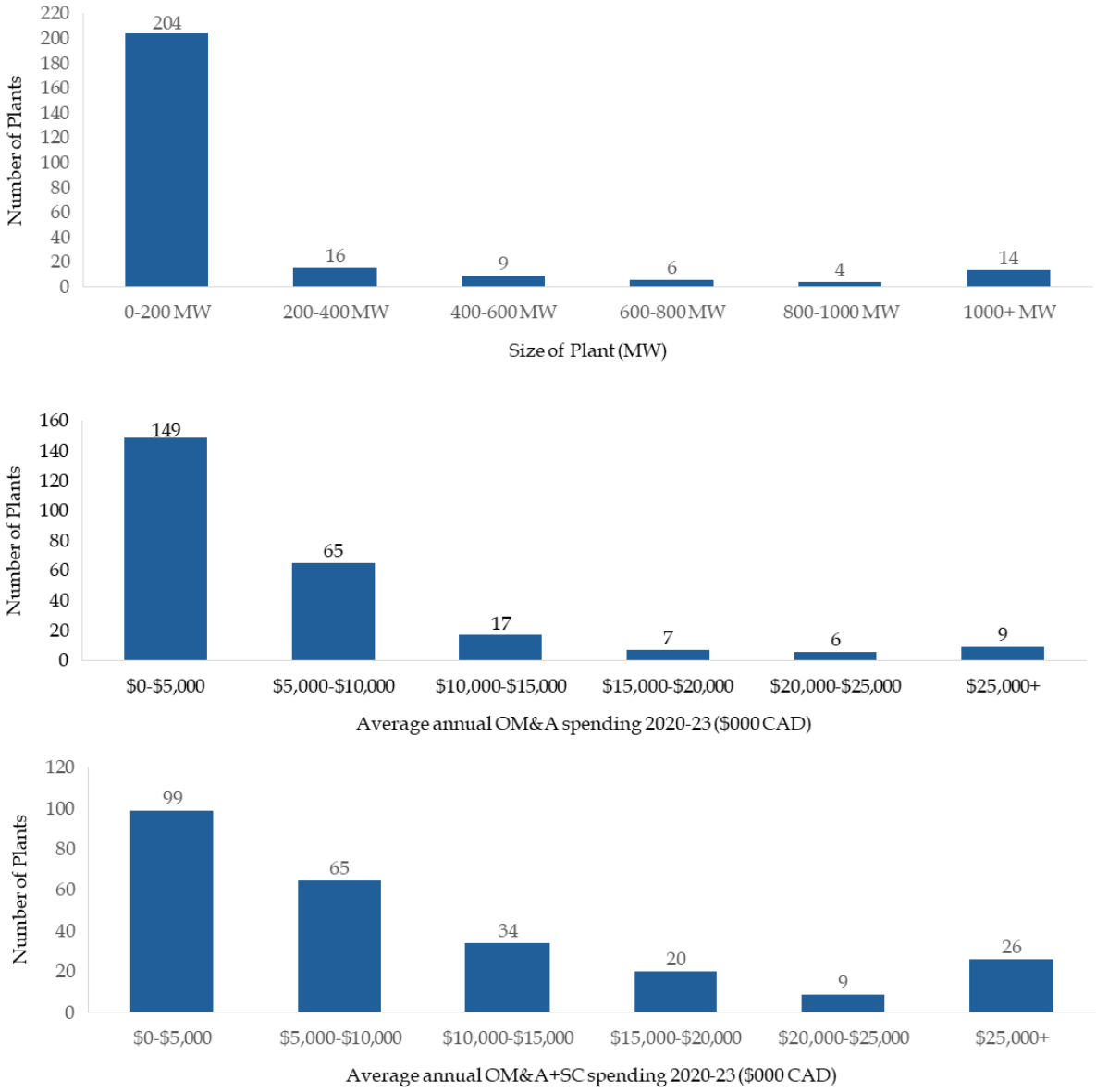
In the EUCG data relied upon by LEI, there were a large number of small hydroelectric plants (204 plants from 0.5 MW to 200 MW in size), and a handful of very large plants (14 plants over 1,000 MW in size) (see Figure 4). This wide range of plant sizes encompasses the range of OPG's regulated plant capacities, and therefore the OPG plants are not outliers on either the low end or the high end of the range of the data.

The range of annual OM&A expenditures corresponding to each plant, as well as OM&A + SC expenditures, was similarly weighted towards the low end of the range, but also encompassed high levels of spending for a few plants.

The categories shown in Figure 4 are for illustrative purposes only – the econometric method used by LEI did not rely on peer-group classification by size, spending, or any other characteristic; instead, it considers each operator's group of plants and each plant's individual information.

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Figure 4. Overview of key data elements



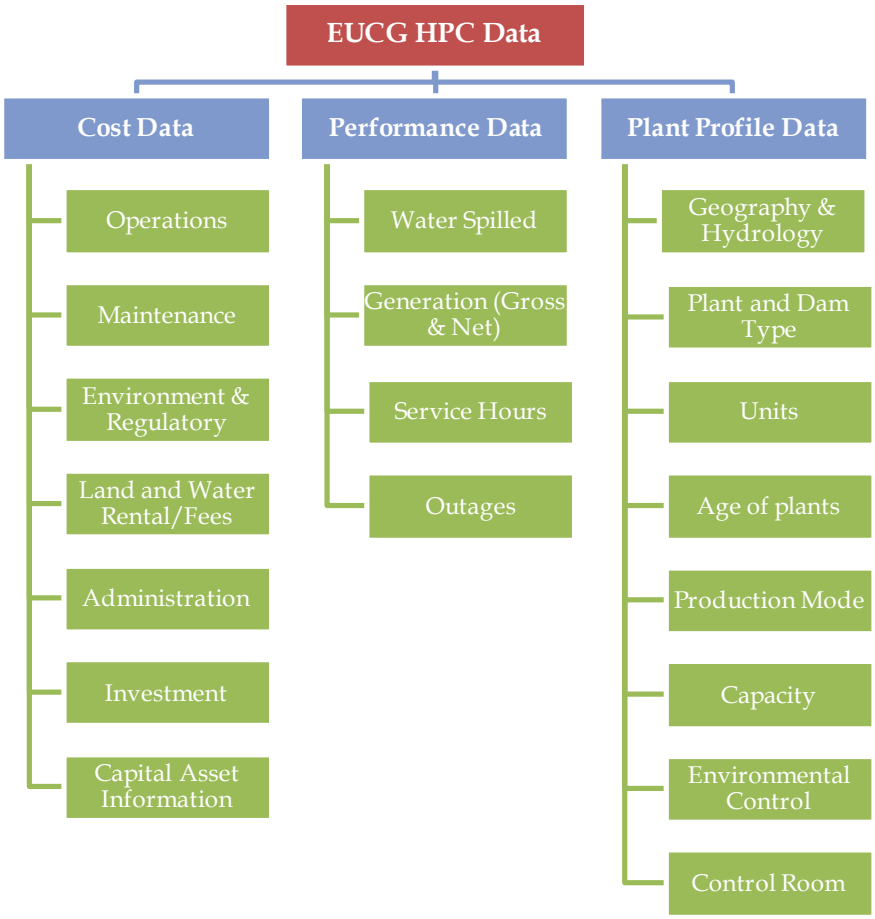
	Minimum	Maximum	Average	Standard Deviation
OM&A expenditure ($000)	$123	$71,438	$6,391	$8,440
OM&A+SC expenditure ($000)	$123	$98,135	$11,068	$14,001
Gross Capacity (MW)	0.50	4215.00	215.38	459.65

3.3 Detailed data definitions

The EUCG HPC data is provided at the plant level, and all direct and allocated expenses are assigned to a specific plant using a prescribed and consistent method. Costs are captured within seven functional areas (see Figure 5). EUCG members report cost data in their local currency. For the US entities included in LEI's TCB study, LEI converted their costs (reported in US dollars)

into Canadian dollars, using the currency conversion factors provided in the EUCG dataset, which are based on purchasing power parity ("PPP").[20]

Figure 5. Expense categories, performance, and plant data reported in the EUCG HPC database



There are several expense categories shown in Figure 5 above that LEI did not include in the TCB study. LEI excluded environmental and regulatory costs, land and water rental fees, and capital investment associated with improvements and additions to plant capability. Environmental and regulatory costs are required expenses and are not directly under the control of management. Land and water rental fees are similarly not under management's control. The timing of capital investments tied to plant enhancements will vary depending on where each company is in its investment cycle and the specific needs of the plant. Moreover, the magnitude of such capital investments can be very large. As noted previously, including these costs in an econometric analysis over a fixed and relatively short timeframe could distort comparisons, given that not all companies would have faced similar capital spending during the study period. Because the EUCG data does not go back far enough in time to allow for accurately capturing the total value of capital for each company, LEI used the data for annual capital expenditures associated with

[20] As per the HPC's 2023 Annual Cost and Performance Report, EUCG finds this currency conversion methodology to provide a more stable and accurate approach than using foreign exchange rates.

sustaining capability only, as reported by the EUCG database.[21] This annual expenditure is included in the total annual expenditure for each company.

Unlike an industry TFP analysis, which is typically used to establish the trend in productivity improvement over time and for a whole industry, a benchmarking study should reflect the ***current*** efficiency of an individual firm relative to others in its industry. As such, LEI examined the period from 2020-2023, rather than a longer historical time series. LEI used four years of data to ensure that results would not be overly influenced by events or issues that only impacted a single year. LEI's benchmarking study used 253 plant observations annually, yielding a total of 1,012 observations over four years. Econometric analysis benefits from having a sufficiently large number of observations, as this improves the precision and reliability of the statistical estimates. Therefore, LEI believes that use of four years of data strikes an appropriate balance: it includes sufficiently recent information to ensure relevance, while also providing enough data points to support a statistically robust analysis.

When performing an econometric analysis, it is not necessary to narrow down the list of peers based on size or business conditions of the company, because these factors are controlled for in the econometric process. There is therefore no subjectivity involved, as there would be in selecting a peer group. Some EUCG plant-level and entity-level observations did not have valid data for some of the expense categories or other independent variables for the entire study timeframe, and therefore LEI excluded them from the study.[22] The data LEI ultimately used had observations for 253 plants owned/operated by 13 hydroelectric power plant operators, including OPG.

3.4 The fixed effects econometric process

An efficient firm produces the maximum output for a given set of inputs; or, alternatively, it uses the lowest-cost set of inputs (i.e., the lowest total OM&A cost and/or OM&A plus sustaining capital spending) to provide a given level of output.

OM&A cost and/or OM&A plus sustaining capital spending depend on the size of the plant, so LEI controlled for the installed capacity of each of the plants. As discussed previously in Section 3.1.2, there are other independent variables that could impact costs, which LEI included. This is where the econometrics process plays a significant role. The econometric process uses the specified economic model and the data, and estimates (based on comparison to the mean value, as described previously) the impact of each independent variable on OM&A cost (or, for the alternative model, OM&A + SC spending). Adding a FE variable allows the economic models to

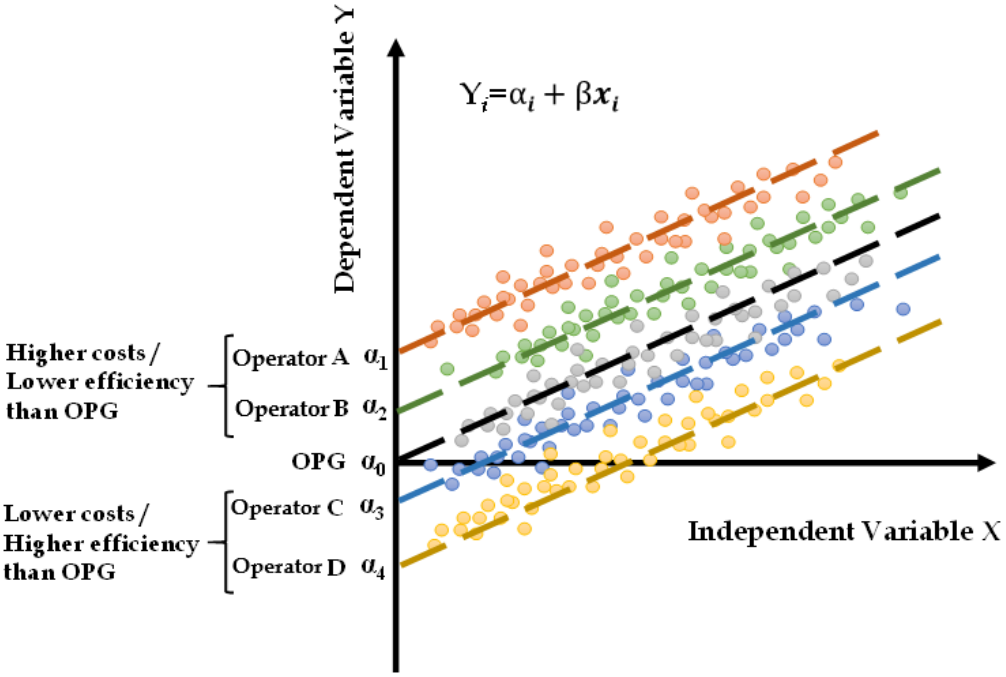
[21] Under the conventional approach for estimating total costs, a company's real capital stock (i.e., the actual price-deflated value of capital) needs to be estimated for every year. In order to calculate real capital stock, it is preferable to have capital input data as far back as possible so that the vintages of additions and retirements can be more accurately accounted for. LEI's approach uses only a subset of capital spending – the portion spent for sustaining capability only.

[22] 5 plants were excluded because they operate outside of the US or Canada, specifically in Africa and South America, thus facing different operating environments, regulatory regimes, and cost structures. 12 plants contracted under Hydroelectric Energy Supply Agreements ("HESAs") were excluded. 139 plants were excluded because of incomplete data during the 2020-2023 study timeframe. 10 plants were excluded because they did not have useable data in at least 1 of the 4 years under study.

capture the impact of ownership on OM&A or OM&A plus sustaining capital spending. The FE measures the impact on the cost of a hydroelectric power plant from being owned by one entity versus another, with all other drivers of costs being held constant.

As noted previously, a FE economic model includes a set of variables which allow cost impacts to be estimated for each owner. The size and sign of the firm-specific coefficients represent the relative efficiency of each operator/owner. The more positive an entity's coefficient is, the higher its OM&A costs or OM&A plus sustaining capital spending (controlling for the other cost drivers in the model), and the less efficient the entity is. LEI set up the models so that OPG's FE is equal to zero. Therefore, the operators that have positive coefficients are less efficient than OPG, and the operators with negative coefficients are more efficient than OPG. Figure 6 below provides an illustration of this concept (for illustrative purposes only, not based on real data). The operator represented by the orange line at the top of the chart (with the intercept α_1) corresponds to the least efficient firm in the chart. The values of α are the estimated coefficients.

Figure 6. Illustrative and simplified example of the FE model



Note: The fixed effect is denoted by α_i, which is the intercept term specific to each operator/owner.

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4 Benchmarking results and implications for setting of the stretch factor

To arrive at a reliable estimate of the average relationship between costs and the independent variables, an econometric model must provide a good fit to the data. LEI's OM&A and OM&A + SC models have overall high explanatory power and good linear fit, as discussed in more detail below.

The individual coefficients for each independent variable in the model measure the size and direction of the impact of the independent variable on the dependent variable (costs). The actual numerical values of the individual coefficients are of less importance in the benchmarking than the overall fit of the model. This is because benchmarking does not require determining elasticities of substitution[23] across inputs, for example, for which precise measurements of individual impacts are needed. Nevertheless, LEI's econometric results showed that the relative magnitudes and signs of those coefficients agree with the economic intuition relating to the independent variables, as discussed further below.

4.1 Key findings

LEI's econometric results show that:

1. **Plant size (gross capacity in MW)** was positively correlated with higher total costs and reflects economies of scale. The coefficient of 0.32 in the OM&A model indicates that costs went up about 0.37% for every 1% increase in plant capacity (computed from the coefficient of 0.32 using $e^{(0.32)}=0.37$ to account for the use of logarithms) (see Figure 7). Because 0.37 is less than one, it indicates that costs went up more slowly than plant size – by only about one-third of the rate – reflecting that, on a dollar-per-MW basis, larger plants are cheaper to operate. This coefficient was statistically significant (the probability value or p-value[24] was 0.00, which indicates a less than 1/100 probability that the coefficient would show up if the impact on cost was really zero). In other words, we can be more than 99% confident in the accuracy of the result compared to a zero impact. LEI included the square of plant size, to capture potential non-linear impacts on cost. The coefficient was 0.02, indicating a small (2%) non-linear impact. In the OM&A + SC model, expected costs went up about 0.68% (computed from $e^{(0.52)}=0.68$) for every 1% increment in plant size (see Figure 8). In the OM&A + SC model, there was no statistically significant non-linear impact on expected cost;

[23] In economics, "elasticity of substitution" is a widely used measurement of how easily one input, like labour, can be substituted for another, like capital. This benchmarking study does not require detailed economic modelling of input substitution.

[24] A p-value means the probability, under a given model, that a statistical summary of the data would be equal to or more extreme than its observed value.

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2. Plants with **staffed control rooms** had expected OM&A costs on average 20% higher than plants with non-staffed control rooms (computed from the coefficient of 0.17, using $e^{(0.17)}$=1.20 to account for the use of logarithms), all else equal. The coefficient is statistically significant. For OM&A + SC spending, the correlation with expected costs was on average 11% higher for plants with staffed control rooms (computed as $e^{(0.11)}$=1.11). However, the p-value of 0.11 (coincidentally, the same value as the coefficient estimate) indicates that we can only be 89% confident in the accuracy of the result compared to a zero impact. This level is too low for generally accepted standards of statistical significance, which ideally require a 95% confidence level;

3. Plants with only **one or two active units** had lower expected costs than plants with more than two active units. In the OM&A model, the impact of having one or two active units was that expected costs would be only 70% of costs for plants with more than two active units ($e^{(-0.40)}$=0.70); the p-value of 0.00 indicates a greater than 99% confidence in the result compared to a zero impact;

4. The **OM&A price** (as well as the **capital price**, in the OM&A + SC model) impact was not statistically significant, as indicated by the p-values. In other words, the results were not statistically different from the assumption that impacts of prices on costs were zero. However, prices are included in the model because economic theory and common sense dictate that the price of inputs should impact total costs. In that case, not controlling for the impact of prices could bias the estimates of the other variables' impacts;

5. **Time** did not have a statistically significant impact on expected costs over the study timeframe, as indicated by the p-values; and

6. The **fixed effects** variables measure the expected impact on cost for a plant not being part of OPG's fleet, as discussed previously. For example, the impact on the expected OM&A cost of being the owner/operator entity "L" is computed from the coefficient 0.7, using $e^{(0.7)}$=2.02 to account for the use of logarithms. This means that entity L's costs are about two times OPG's OM&A costs, all else equal. On average, the non-OPG entities differed from OPG by a FE coefficient of 0.35, in other words, $e^{(0.35)}$=1.42; therefore, on average, their expected OM&A costs were 42% higher than OPG's, all else equal. For the OM&A + SC model, the non-OPG entities differed from OPG by an average FE coefficient of 0.14, in other words, $e^{(0.14)}$=1.15; therefore, on average, their expected OM&A + SC costs were 15% higher than OPG's, all else equal. The range of efficiencies implied by LEI's results is wide, but, as noted previously, such ranges are not uncommon for the results of efficiency studies.[25]

Econometric tests showed that the linear fit of both models was good. The coefficient of correlation (i.e., the "adjusted R-squared" or "adjusted R^2") measures the dispersion of the data

[25] See, for example, "Empirical Research in Support of Incentive Rate Setting in Ontario: Report to The Ontario Energy Board." Pacific Economics Group Research, LLC. May 2013; "Statistical Research for Public Service Company of Colorado's Multiyear Rate Plan." Pacific Economics Group Research, LLC. May 2017; and "Benchmarking the Total Cost of NSTAR Gas Company." London Economics International LLC. Massachusetts DPU 19-120, November 2019.

around the line-of-best-fit. The R^2 value for any line-of-best-fit will range from 1 (if all the data points are exactly on the line-of-best-fit – i.e., a perfect correlation) to as low as 0 (if the data are very dispersed, noisy, or have an intrinsically non-linear relationship to the dependent variable). An R^2 of 0 implies that there is no correlation that can be explained by the line-of-best-fit. R^2 does not measure the relationship between the dependent variable and independent variables. It simply measures the dispersion of the data around the line-of-best-fit. The R^2 values for LEI's OM&A and OM&A + SC models are 0.784 and 0.733, respectively (as shown in Figure 7 and Figure 8), indicating a good linear fit for each of the models.

Figure 7. LEI's OM&A econometric results

Explanatory variable	Parameter estimate (coefficient)	Multiplier for impact on expected cost (exponentiated coefficient)	T-statistic	P-value
Gross capacity	0.32	1.37	8.93	0.00
(Gross capacity)^2	0.02	1.02	3.63	0.00
Staffed control room (1 = staffed, 0 = unstaffed)	0.17	1.2	3.09	0.00
Two or less active units (1 = two or less, 0 = more than two)	-0.40	0.7	-9.24	0.00
OM&A price index	-2.14	0.1	-0.52	0.60
(OM&A price index)^2	0.91	2.5	0.70	0.48
Time	-0.02	1.0	-0.20	0.84
Fixed effects:				
OPG	0.00	1.00	(defined, not estimated)	
FE_A	-0.39	0.68	-1.86	0.02
FE_B	-0.04	0.96	-0.12	0.62
FE_C	0.20	1.22	0.60	0.84
FE_D	0.25	1.28	0.73	0.92
FE_E	0.30	1.35	1.06	0.85
FE_F	0.35	1.42	1.23	0.91
FE_G	0.44	1.56	1.59	0.99
FE_H	0.46	1.58	1.59	1.03
FE_I	0.60	1.82	2.11	1.16
FE_J	0.66	1.93	1.96	1.32
FE_K	0.67	1.95	2.32	1.23
FE_L	0.70	2.02	2.23	1.32
Average fixed effect excluding OPG	0.35	1.42		
	Adjusted R^2	0.784		
	Sample period	2020-2023		
	Number of observations	1,012		

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Figure 8. LEI's OM&A + SC econometric results

Explanatory variable	Parameter estimate (coefficient)	Multiplier for impact on expected cost (exponentiated coefficient)	T-statistic	P-value
Gross capacity	0.52	1.68	12.07	0.00
(Gross capacity)^2	0.00	1.0	0.23	0.82
Staffed control room	0.11	1.11	1.58	0.11
Two or less active units (1 = two or less, 0 = more than two)	-0.31	0.7	-6.04	0.00
OM&A price index	0.19	1.2	0.09	0.93
Capital price index	0.79	2.20	0.29	0.77
Time	-0.05	1.0	-0.29	0.77
Fixed effects:				
OPG	0.00	1.00	(defined, not estimated)	
FE_A	-0.35	0.70	-1.29	0.20
FE_B	-0.11	0.90	-0.20	0.84
FE_C	-0.09	0.91	-0.17	0.86
FE_D	0.00	1.00	0.01	0.99
FE_E	0.03	1.03	0.06	0.95
FE_F	0.09	1.09	0.16	0.87
FE_G	0.09	1.10	0.17	0.87
FE_H	0.25	1.29	0.48	0.63
FE_I	0.28	1.32	0.53	0.60
FE_J	0.32	1.37	0.60	0.55
FE_K	0.41	1.51	0.76	0.45
FE_L	0.71	2.04	1.37	0.17
Average fixed effect excluding OPG	0.14	1.15		
	Adjusted R^2	0.733		
	Sample period	2020-2023		
	Number of observations	1,012		

4.2 OPG ranks in the first quintile for OM&A cost efficiency and second quintile for OM&A + SC

The econometric results provide the basis for the efficiency rankings of the operators/owners (see Figure 9 and Figure 10, where the blue bars show the coefficients of the FE estimates in order of size for the OM&A model and the OM&A + SC model, respectively). OPG ranked 3rd in the OM&A model (first quintile) and 4th in the OM&A + SC model (second quintile) over the study period among the 13 operators/owners. The visual representations in Figure 9 and Figure 10 demonstrate that OPG's costs (controlling for the prices of inputs, the capacity of its plants, control room staffing, and the number of active units) were materially below average (indicated by the red vertical lines in Figure 9 and Figure 10) and below most of the other operators/owners' costs.

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Figure 9. Relative efficiency ranking for the OM&A model

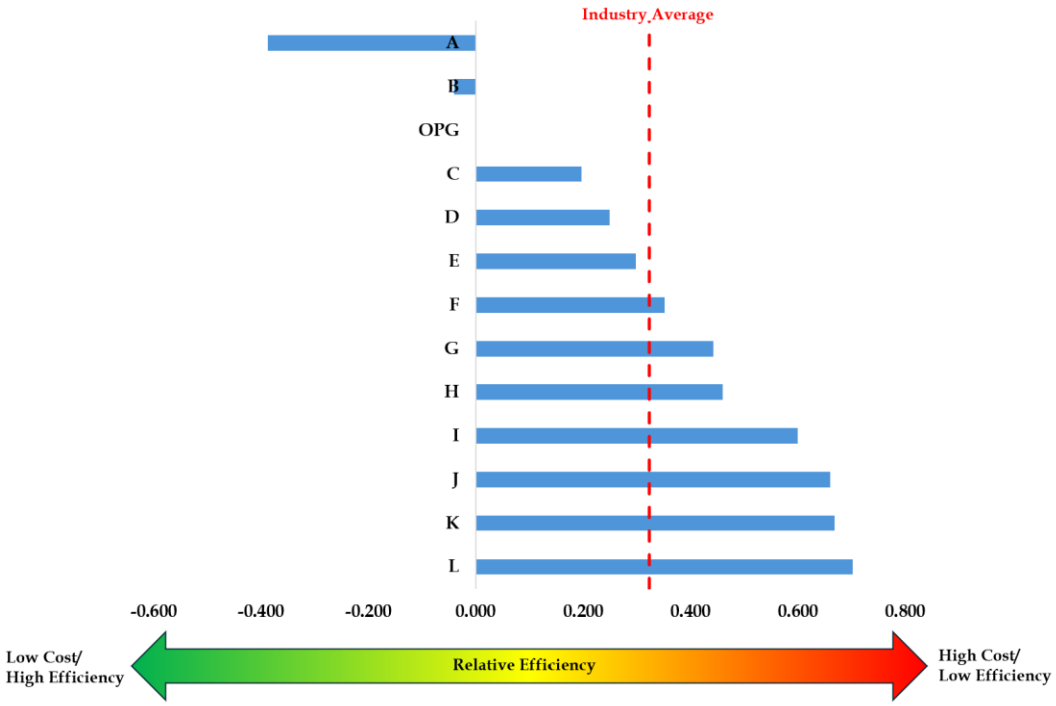
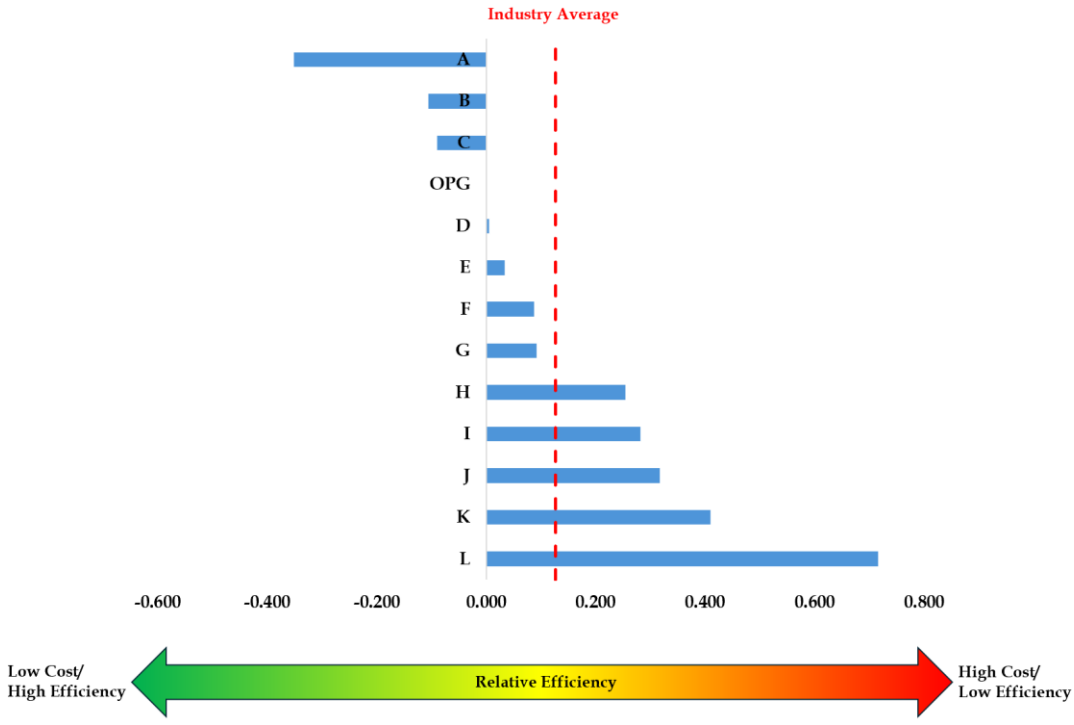


Figure 10. Relative efficiency ranking for the OM&A + SC model



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4.3 Implications for the stretch factor

Overall, LEI's econometric analysis showed that, over the 2020-2023 period, OPG's OM&A expenditures and OM&A + SC expenditures were substantially lower than the expected cost of the other operators/owners on average, after controlling for the prices of inputs, the capacity of its plants, control room staffing, the number of active units, and time. According to LEI's econometric analysis, OPG's OM&A costs over the 2020-2023 period were 42% below expected (predicted) levels. Given the OEB's established cohorts for stretch factor assignment (shown in Figure 1 previously), this would suggest the lowest stretch factor of 0%. OPG's OM&A + SC expenses were 15% below expected levels, corresponding to a stretch factor of 0.15%. Therefore, LEI recommends a stretch factor for OPG in the range of 0% to 0.15%.

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5 Appendix A: Alternative econometric approaches considered

There are other approaches to benchmarking efficiency using econometrics. LEI considered them in its initial development of the study, but each had drawbacks as discussed below, and were therefore not employed.

1. **Corrected ordinary least squares ("COLS")** is a partly deterministic and partly statistical technique which identifies a cost or expenditure frontier (rather than an average function) by identifying the observation (a single firm or plant, in a single year) with the maximum negative residual in a function and using that residual to shift the whole function. The implicit assumption is that all observed deviations from the frontier are due to firm inefficiency. However, this technique ignores random noise or measurement error and can be unduly influenced by outliers.

2. **Stochastic frontier analysis ("SFA")** allows estimation of a cost or expenditure function directly with two components in the residual, one for random noise, and the other for efficiency. SFA is only reliable in a large sample – i.e., as *t* (the time series feature of the panel) approaches a very large number of years. As LEI used only four years of data (to capture recent cost efficiency), this approach was not appropriate.

3. **Translog cost function with input share equations:** Cost or expenditure benchmarking studies are often conducted using a transcendental logarithmic ("translog") function and associated input cost share equations. The translog system posits that the dependent variable (total expenditures) depends on the level of output of a firm, the price of the firm's inputs, and possibly other factors that can impact total spending. However, the translog system requires at least two inputs, so could not be used for the OM&A model. For consistency, LEI did not use it for the OM&A + SC model.

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6 Appendix B: List of acronyms

AWE	Average Weekly Earnings
BEA	US Bureau of Economic Analysis
BLS	US Bureau of Labor Statistics
COLS	Corrected ordinary least squares
ECI	Employer Cost Index
EUCG	Electric Utility Cost Group
FE	Fixed effects
FERC	Federal Energy Regulatory Commission
GDP-PI	Gross Domestic Product Price Index
GDP-IPI FDD	Gross Domestic Product Implicit Price Index – Final Domestic Demand
HPA	Hydroelectric payment amounts
HPC	Hydroelectric Productivity Committee
IR	Incentive ratemaking
I-X	Inflation factor minus Productivity factor
LEI	London Economics International LLC
MW	Megawatt
OEB	Ontario Energy Board
OM&A	Operations, maintenance, and administration
OM&A + SC	OM&A plus sustaining capital spending
OPG	Ontario Power Generation
PBR	Performance-based regulation
SFA	Stochastic frontier analysis
TCB	Total cost benchmarking
TFP	Total factor productivity
X factor	Productivity factor

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2024 Regulated Hydroelectric Performance Scorecard

Performance Outcomes	Measures	2020	2021	2022	2023	2024			Historical Trend	2025 Target
						Actual	Target			
Safety & Environment	Total Recordable Injury Frequency (per 200k hours)[1]	1.21	1.02	1.56	0.46	0.77	1.11	●	+	1.05
	Environmental Performance Index (%)	100%	83%	100%	94%	99%	80%	●	+	85%
Reliability	Availability Factor (%)	88.8%	88.4%	87.8%	85.4%	85.2%	87.1%	●	N	87.5%
	Equivalent Forced Outage Rates (%)	5.7%	3.5%	4.1%	2.9%	5.5%	2.7%	●	-	3.2%
Cost Effectiveness	OM&A Unit Energy Cost ($/MWh)	8.5	10.0	9.6	10.2	10.0	11.0	●	N	11.5
	Regulated Facilities Total Generating Cost per Net MWh ($/MWh)[2]	25.3	27.6	28.7	31.0	32.0	N/A		-	N/A

Notes:

1:Total Recordable Injury Frequency (per 200k hours) is reported on OPG's Renewable Generation (RG) business which includes regulated and non-regulated facilities.

2: Per OEB requirements, no target is filed for TGC.

Legend:

5-year Trend

+	Favourable
-	Unfavourable
N	Neutral

Current Year

● Target met ● Target not met

2024 OPG Scorecard Management Discussion & Analysis
"2024 Scorecard MD&A"
Regulated Hydroelectric Facilities Performance Measures

OPG's regulated hydroelectric fleet consists of 54 stations with a combined installed capacity of 6,566 MW. The objectives of OPG's hydroelectric operations include operating and maintaining the generating facilities in a safe, reliable, efficient and cost-effective manner, while increasing the output from, and pursuing opportunities to increase, the fleet's generating capacity. OPG aims to increase the hydroelectric facilities' output by improving operational flexibility, enhancing reliability, and, subject to water conditions, increasing availability to meet electricity system demand.

Given the long-term nature of OPG's hydroelectric fleet, OPG maintains and improves the performance of existing hydroelectric generating stations through multi-year capital and non-capital investments including replacements and upgrades of turbine runners, and refurbishment or replacement of existing generators, transformers and control systems. OPG pursues opportunities to refurbish, expand or redevelop its existing hydroelectric stations. The cornerstone of OPG's project prioritization and maintenance approaches for the hydroelectric assets is that safety, environmental, other regulatory programs and alignment with strategic goals, such as OPG's Climate Action Plan, are of the highest priority.

During 2024, the Environmental Performance Index ("EPI"), Total Recordable Injury Frequency ("TRIF") and OM&A Unit Energy Cost ("UEC") performance measures were better than target while Availability Factor and Equivalent Forced Outage Rates ("EFOR") performance measures were below target. Total Generating Cost per Net MWh ("TGC") for the regulated hydroelectric facilities increased in 2024 when compared to 2023. Performance measures and 2024 performance results are further detailed below.

Hydroelectric Safety & Environment

- **Total Recordable Injury Frequency (per 200k hours)**

Total Recordable Injury Frequency

TRIF is defined as the average number of lost time injuries, medically treated injuries and restricted work injuries (aka recordable injuries) per 200,000 hours worked. A low TRIF numerical value is good.

The 2024 TRIF performance was the second-best performance since OPG's inception (0.77 compared to target of 1.11), with the best TRIF score (0.46) performance in 2023. There was however, an increase in low-energy events caused by hand/finger injuries throughout 2023 and 2024. RG will continue to have an added focus on preventing injuries to hands through a "Glove of the Month" campaign, Dynamic Learning Activities that demonstrate that all tasks can be performed with the right gloves and an added focus on selecting the right gloves in the Safe Work Planning process. Continued focus on supervisory field presence through the Observing & Coaching program, increased efforts to share lessons learned and successes, and enhancing soft skills for more meaningful and engaging pre-job briefs and tailboards will be a focus in 2025 to strengthen H&S culture and reduce recordable events in 2025.

- **Environmental Performance Index (%)**

EPI is a weighted distribution of multiple measures, including the number of environmental spills and environmental regulatory infractions with a target performance of 80%.

In 2024, the regulated hydroelectric facilities' EPI performance score was (99%) which outperformed the 2024 target (80%). This performance is due to robust programs to prevent category A or B spills, to satisfy Environmental Compliance Assessment inspections, track and remove PCB containing equipment and maintain an ISO14001-certified Environmental Management System.

Hydroelectric Reliability

- **Availability Factor (%)**

The Availability Factor ("Availability") is a measure of the generating unit reliability. It is the percentage of generating potential that could have been provided after considering outages and derates, but it does not conisder the availability of fuel. Unit Hours that are not spent in outage states are weighted by the respective unit's Maximum Continuous Rating (MCR). Outages caused by external factors are not considered.

Availability in 2024 was close to 2023 (85.2% in 2024 vs 85.4% in 2023). Availability across the regulated fleet was 1.9% under the 2024 target performance (87.1%). The deviation is mainly attributable to forced outage events.

- **Equivalent Forced Outage Rates (%)**

EFOR is an index of generating unit reliability measured by the ratio of time a generating unit is forced out-of-service, including equivalent forced deratings, to the time the unit was operating or was forced out-of-service completely or partially. Unit hours are weighted by Maximum Capacity Ratings thus EFOR is a measure of generation loss as a function of intended service. Planned maintenance time, states where units are considered available but not operating, and outages due to external causes are not considered when calculating EFOR.

EFOR increased from 2.9% in 2023 to 5.5% in 2024, which was higher than the target performance (2.7%). EFOR in all regions increased from 2023 to 2024, with the Eastern region having the most substantial increase.

Hydroelectric Cost Effectiveness

- **OM&A Unit Energy Cost ($/MWh)**

UEC is a measure of financial productivity. It measures the Operations, Maintenance and Administrative (OM&A) costs per unit of energy produced (in MWh). UEC is calculated as the total OM&A expenditures, divided by annual generation.

The 2024 UEC ($10.0/MWh) improved over the 2024 performance target ($11.0/MWh). This improvement was primarily due to lower project OMA expenses than plan driven by lower costs and higher than plan generation. The 2024 UEC ($10.0/MWh) was lower than the 2023 UEC ($10.2/MWh) mainly due to increased generation of 1.1TWh resulting from lower SBG-related foregone production and higher water flows across most of Ontario.

- **Regulated Facilities Total Generating Cost per Net MWh ($/MWh)**

TGC is defined as the total cost of operating the regulated hydroelectric facilities, which includes OM&A, fuel (water), and sustaining capital, divided by generation. TGC is measured as a 3-year historical average to account for year-over-year fluctuations in capital expenditures.
The TGC increased by 3% from $31.0/MWh in 2023 to $32.0/MWh in 2024. The increase is primarily due to higher capital investments in refurbishment programs to address asset end of life offset by higher generation due to higher water flows.

Note to Readers of 2024 Scorecard MD&A

This Scorecard MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "budget", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could" and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks and uncertainties. All forward-looking statements could be inaccurate to a material degree. Some of the factors that could cause such inaccuracies include, but are not limited to, legislative or regulatory developments, financial market conditions, general economic conditions and the weather. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station (GS) performance, availability and operating lives, fuel costs, surplus baseload generation (SBG), fixed asset removal and nuclear waste management and associated funding requirements, refurbishment of existing facilities, development and construction of new facilities, defined benefit pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of electricity industries and markets, the continued application and renewal of energy supply agreements (ESAs), foreign currency exchange rates, commodity prices, wholesale electricity market prices, environmental and other regulatory requirements, health, safety and environmental developments, the COVID-19 pandemic, changes in the Company's workforce, renewal of union collective agreements, business continuity events, the weather, climate change, technological change, financing requirements and liquidity, funding sources, applications to the Ontario Energy Board (OEB) for regulated prices, the impact of regulatory decisions by the OEB, forecasts of earnings, cash flow, earnings before interest, income taxes, depreciation and amortization, gross margin, Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC) per megawatt-hour (MWh), operations, maintenance and administration (OM&A) expenses and project and other expenditures, retention of critical talent, and supplier and third party performance. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this Scorecard MD&A are made only as of the date of this Scorecard MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events or otherwise.

2024 Nuclear Performance Scorecard

Performance Outcomes	Measures (single-year unless otherwise noted)		2020	2021	2022	2023	2024		Historical Trend		2025
			Actual	Actual	Actual	Actual	Actual	Target			Target
Safety	**Total Recordable Injury Frequency** (#/200k hours worked)										
		Pickering	0.19	0.10	0.27	0.20	0.20	0.20	●	-	0.20
		Darlington	0.25	0.07	0.08	0.00	0.20	0.20	●	+	0.20
	Total Industrial Safety Accident Rate (#/200k hours)[1]										
		Pickering	0.00	0.03	0.00	0.00	0.00	0.00	●	+	0.00
		Darlington	0.00	0.00	0.00	0.00	0.00	0.00	●	+	0.00
	Collective Radiation Exposure (person rem/unit)										
		Pickering	107.41	67.74	69.99	67.17	103.50	78.90	●	+	59.30
		Darlington	29.97	110.47	29.90	15.64	19.81	84.80	●	+	25.57
	Airborne Tritium Emissions (curies/unit)										
		Pickering	2,918	2,331	2,229	2,164	1,820	2,170	●	+	2,000
		Darlington	879	905	1,157	1,000	958	1,305	●	-	1,215
	Fuel Reliability Index (microcuries /gram)										
		Pickering	0.0001	0.0008	0.0002	0.0003	0.0002	0.0005	●	+	0.0005
		Darlington	0.0035	0.0002	0.0001	0.0001	0.0029	0.0005	●	+	0.0005
	Reactor Automatic and Manual Trip Rate (#/7000 hours)[2]										
		Pickering	0.000	0.000	0.139	0.247	0.320	0.500	●	-	0.500
		Darlington	0.000	0.000	0.000	0.100	0.100	0.500	●	-	0.500
	Auxiliary Feedwater System Unavailability (#)										
		Pickering	0.0118	0.0085	0.0010	0.0000	0.0000	0.0000	●	N	0.0000
		Darlington	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	●	N	0.0000
	Emergency AC Power Unavailability (#)										
		Pickering	0.000	0.0000	0.0000	0.0000	0.0000	0.0000	●	N	0.0250
		Darlington	0.000	0.0000	0.0000	0.0000	0.0000	0.0000	●	N	0.0000
	High Pressure Safety Injection Unavailability (#)										
		Pickering	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	●	N	0.0200
		Darlington	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	●	N	0.0000
Reliability	**WANO Nuclear Performance Index Rolling Average** (%)[3]										
		Pickering	82.50	73.80	80.90	81.20	84.95	85.00	●	+	82.75
		Darlington	93.60	85.80	91.40	89.40	74.74	78.90	●	-	80.20
		OPGN	85.30	76.80	82.40	82.30	83.25	84.20	●	+	82.24
	Forced Loss Rate (%)										
		Pickering	2.65	6.22	1.81	2.78	2.56	3.50	●	+	3.50
		Darlington	1.54	3.52	7.51	1.44	12.07	4.61	●	-	3.61
	Unit Capability Rate (%) [4]										
		Pickering					96.36	96.37	●		96.20
		Darlington					86.97	94.12	●		95.28
		OPGN					92.71	95.54	●		95.67
	Unit Capability Factor (%)[4]										
		Pickering	76.25	78.92	80.01	80.66	83.30	80.91	●	+	89.14
		Darlington	93.05	82.66	86.99	96.99	74.58	81.26	●	-	94.19
		OPGN	84.45	80.70	82.66	86.68	79.90	81.04	●	-	91.99
	Chemistry Performance Indicator (Index)										
		Pickering	1.06	1.06	1.03	1.18	1.22	1.15	●	-	1.09
		Darlington	1.01	1.01	1.00	1.01	1.03	1.00	●	N	1.05
	On-line Deficient Non-Critical Backlog (work orders / unit)										
		Pickering	88.00	68.00	39.80	29.50	20.20	20.00	●	+	14.00
		Darlington	96.00	70.33	61.00	29.00	17.33	20.00	●	+	14.00
	On-line Deficient Critical Backlog (work orders /unit)										
		Pickering	0.50	1.30	0.80	0.67	0.60	0.00	●	+	0.00
		Darlington	1.33	0.00	0.00	0.00	0.00	0.00	●	+	0.00
	On-line Corrective Non-Critical Backlog (work orders /unit)										
		Pickering	3.00	6.30	3.80	0.83	1.20	1.00	●	+	0.00
		Darlington	2.30	2.00	0.50	0.00	0.00	0.00	●	+	0.00
	On-line Corrective Critical Backlog (work orders /unit)										
		Pickering	0.00	0.30	0.00	0.00	0.00	0.00	●	+	0.00
		Darlington	0.30	0.00	0.00	0.00	0.00	0.00	●	+	0.00
Cost Effectiveness [5]	**Total Generating Cost per Net MWh** ($/MWh)										
		Pickering	67.87	64.75	60.05	69.98	64.30	67.51	●	+	74.88
		Darlington	54.30	79.27	101.52	108.85	141.94	127.08	●	-	71.94
		OPGN	60.66	71.53	76.38	85.73	91.78	89.35	●	-	73.2
	Normalized Total Generating Cost per Net MWh ($/MWh)										
		Pickering	47.94	44.76	39.55	48.02	41.74	44.22	●	+	34.09
		Darlington	32.23	45.59	33.88	36.60	51.27	42.85	●	-	33.83
		OPGN	39.71	45.15	37.32	43.40	45.15	43.71	●	-	33.95
	Total Generating Cost per Unit ($M/unit)										
		Pickering	232.32	227.59	214.11	250.49	228.49	231.25	●	-	295.48
		Darlington	389.17	489.03	663.52	796.56	780.21	755.89	●	-	505.78
		OPGN	287.43	314.74	331.65	387.01	372.79	362.41	●	-	385.61
	Normalized Total Generating Cost per Unit ($M/unit)										
		Pickering	177.15	169.54	151.79	184.98	159.69	163.50	●	+	163.52
		Darlington	241.83	297.90	238.91	287.92	308.25	278.33	●	-	247.89
		OPGN	184.49	212.33	174.57	210.71	198.55	192.21	●	-	199.68
	Non-Fuel Operating Cost per Net MWh ($/MWh)										
		Pickering	59.97	57.24	54.40	63.24	57.65	60.75	●	-	61.27
		Darlington	36.91	57.64	64.98	67.14	95.70	88.53	●	-	48.10
	Normalized Non-Fuel Operating Cost per Net MWh ($/MWh)										
		Pickering	--	--	--	--	--	--	-		--
		Darlington	31.33	47.29	41.51	41.83	63.04	55.44	●	-	37.72
	Fuel Cost per Net MWh ($/MWh)										
		Pickering	3.89	3.72	3.75	3.90	4.29	4.31	●	-	6.80
		Darlington	4.22	4.00	3.82	4.32	5.29	4.62	●	-	5.02
	Capital Cost per MW Design Electrical Rating ($k/MW)										
		Pickering	26.59	25.79	13.12	19.71	16.27	16.31	●	+	34.71
		Darlington	107.55	123.88	243.57	311.66	256.36	229.91	●	-	150.71
	Normalized Capital Cost per MW Design Electrical Rating ($k/MW)										
		Pickering	--	--	--	--	--	--	-		--
		Darlington	82.96	90.52	104.28	133.09	111.39	106.91	●	-	110.40
Human Resources	**18-month Human Performance Error Rate** (#/200k ISAR and contractor hours)										
		Pickering	0.0200	0.0200	0.0600	0.0600	0.0000	0.0000	●	N	0.0000
		Darlington	0.0200	0.0180	0.0000	0.0000	0.0019	0.0000	●	+	0.0000

Note 1 *: Industrial Safety Accident Rate (ISAR2) has been replaced by Total Industrial Safety Accident Rate (TISA2) in Q1 2024 to align with NPI methodology transition form Method 4 to Method 10. ISAR included only permanent employees when counting industrial safety accidents, while the new indicator TISA includes both contractors and permanent employees.*

Note 2: *Rector Trip Rate was replaced by Reactor Automatic & Manual Trip Rate following the NPI Method 10 transition in 2024. The indicator change includes the change from Unplanned Automatic Scrams (UA7) to Unplanned Total Scrams (US7). Method 4 utilized UA7 metric which only included the automatic scram data. The new indicator, US7, which includes both automatic and manual scrams.*

Note 3 *: The Nuclear Performance Index Method 10 is a WANO sponsored performance measure and is a weighted composite of ten WANO Performance Indicators related to safety and production performance reliability. In Q1 of 2024, Method 10 replaced Method 4: Unit Capability Factor (UCF) was replaced by Unit Capability Rate (UCR) , Automatic Reactor Scrams (UA7) was replaced by Automatic and Manual Scrams (US7,) and Industrial Safety Accident Rate (ISAR2) – replaced by Total Industrial Safety Accident Rate (TISA2). NPI is calculated using a 2-year rolling average for PN and a 3-year rolling average for DN.*

Note 4 *: UCR replaced UCF due to NPI methodology change from Method 4 to Method 10 in Q1 of 2024. UCF will continue to be reported as UCF incorporates additional factors that impact production (i.e. Unbudgeted Planned Outages).*

Note 5 *: Value for Money metric targets are subject to change upon finalization of assumptions and cost allocations.*

Current Year		
● Target met	+	Favourable
● Target not met	-	Unfavourable
	N	Neutral

DRIVERS OF DEFICIENCY- OPG NUCLEAR FACILITIES

1.0 PURPOSE

This evidence presents the major drivers of revenue deficiency for OPG's nuclear facilities over the 2027-2031 period as set out in Ex. I1-1-1, Table 5b.

2.0 OVERVIEW

Approximately 80% of the revenue deficiency for OPG's nuclear facilities over the IR term is driven by the decision to refurbish Pickering Units 5-8 including the capital-related revenue requirement of the Pickering Refurbishment Program ("PRP") and ongoing station operations. This also includes the impact of concurrent cost recovery, recovering interest amounts associated with the PRP prior to such assets being placed in service as prescribed by O. Reg. 53/05 (Ex. I1-1-3). The other main contributing factors are the updated cost of capital parameters and OPG's request for a capital structure of 52% equity and 48% debt to reflect changes to its risk profile risk and relative to proxy groups. Other major drivers of deficiency include an increase in rate base for Darlington reflecting the ongoing capital portfolio program as well as certain major investments necessary to address emergent reliability risks to Darington's post-refurbishment operations. This is partly offset by higher nuclear production over the period (Ex. E2-1-1).

The annual revenue deficiency impact of revenue requirement drivers is detailed in Chart 1 and explained in Section 3.0 below.

To determine the revenue deficiency for the nuclear facilities, OPG calculated an indicated production revenue for each year between 2027 and 2031 by multiplying each year's production forecast by the 2026 nuclear payment amount approved in EB-2020-0290. Comparing the indicated production revenue in each year to the annual revenue requirements proposed in this application shows revenue deficiencies of $1,981.8M in 2027, $1,285.7M in 2028, $1,885.8M in 2029, $1,895.4M in 2030, and $2,514.7M in 2031.[1]

[1] See Chart 1 below, Line 11.

3.0 DRIVERS OF DEFICIENCY FOR THE NUCLEAR FACILITIES

3.1 Pickering Continued Operations (+78% of revenue deficiency)

Pickering Refurbishment Program

The Pickering Refurbishment Program accounts for +41% deficiency and includes the cost of capital and depreciation impact upon Unit 5 entering rate base in 2031 (Ex. D2-3-8 and Ex. F4-1-1, respectively) and associated Project OM&A expenses (Ex. F2-8-1). It also includes the impact of recovering interest amounts associated with PRP prior to such assets being placed in service as prescribed by O. Reg. 53/05 (Ex. I1-1-3). These items contribute a $3,878.1M increase in revenue requirement over the IR term.

Pickering Operations

The operation of Pickering during the IR term accounts for +37% deficiency and includes costs associated with sustaining Pickering operations for transition into the post-refurbishment period and ensuring it remains in compliance with regulatory requirements during the refurbishment period and maintains readiness for return to service. The 2026 nuclear revenue requirement approved in EB-2020-0290 did not contemplate the operation of Pickering beyond 2025. Incremental costs are primarily driven by OM&A expenditures for Pickering Cyclical Maintenance activities as discussed in Ex. F2-4-1, base OM&A costs for Station and Operations and Project Support as discussed in Ex. F2-2-1, and the allocation of OPG's central and common costs as discussed in Ex. F3-1-1. The higher base OM&A costs toward the end of the IR term are due to the Pickering Unit 5 return to service. The 2027-2031 IR term also includes the cost of capital and depreciation associated with establishing a sustaining project portfolio at Pickering in preparation for "second life" operations as discussed in Ex. D2-1-3. The total impact of Pickering Operations is $3,554.0M over the IR term.

3.2 Lower Production (offsets revenue deficiency by 19%)

Relative to the annual OEB-approved nuclear production for 2026, forecast nuclear production decreases by 3.2 TWh in 2027, increases by 4.8 TWh in 2028, increases by 3.2 TWh in 2029, increases by 5.4 TWh in 2030, and increases by 9.0 TWh in 2031. The primary driver of the lower production in 2027 is a combination of planned outages at Darlington including higher planned outage days to execute emergent work associated with the Primary Moisture

Separator Replacement ("PMSR") on all four Steam Generators in Darlington Unit 2 and a planned Vacuum Building Outage ("VBO") which necessitates the shutdown of Units 1, 3, and 4 while Unit 2 is already in a planned outage. This is partially offset by higher production in 2027 due to the full year impact of the return to service of Unit 4 as part of the Darlington Refurbishment Program ("DRP") in 2026.

The increases in production for the subsequent years reflect the completion of the DRP and the nuclear outage profile planned over the IR term (Ex. E2-1-2). The increase in overall production over the IR term helps offset the revenue deficiency by $1,854.4M.

3.3 Cost of Capital (+11% of revenue deficiency)

The cost of capital impact is $1,015.7M over the IR term. OPG is seeking approval of cost of capital amounts over the IR Term based on a capital structure of 52% equity and 48% debt. The proposed capital structure reflects the material increase in OPG's business risk profile since EB-2020-0290 and relativity to proxy groups whom have a mean and median equity ratio as discussed in Ex. C1-1-1. 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. The Application incorporates an ROE of 9.11% 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, EB-2024-0063, March 27, 2025.

3.4 Darlington Projects (excluding DRP) (+9% of revenue deficiency)

The increase in revenue requirement related to Darlington projects reflects the cost of capital and depreciation on the increase in rate base compared to the 2026 OEB-approved amount reflecting the ongoing capital portfolio program as well as certain major investments necessary to address emergent reliability risks to Daringtonʼs post-refurbishment operations. This includes the Darlington Turbine Rotor Replacements, Darlington Unit 1 and 2 Generator Stator Rewind, and Darlington SG Primary Moisture Separator Replacements. Refer to Ex. D2-1-3 for further details. The impact over the IR term is $853.9M.

3.5 Darlington Outage OM&A Expenses (+5% of revenue deficiency)

Darlington outage OM&A costs are forecasted to increase by $486.3M over the 2027-2031 period relative to EB-2020-0290 approved level for 2026. All years in the IR term are higher than the Darlington outage OM&A costs for 2026 approved in EB-2020-0290 as 2026 only had no major planned outages scheduled. The outage costs reflect the nuclear outage profile planned over the IR term (Ex. E2-1-2, Ex. F2-4-1 and Ex. F2-4-2).

3.6 Other (+17% of revenue deficiency)

The other drivers of deficiency include the DRP, higher nuclear fuel costs and other OM&A expenses not covered by the above categories. The impact over the IR term is $1,629.8M.

Remaining/Other OM&A expenses are changes in OM&A expenses that do not include DRP, PRP, DNNP, Pickering Operations, and Darlington outages. Drivers of the increase include higher costs across Darlington Station, Operations and Project Support and Corporate Support Services relative to 2026 OEB-approved levels. These increases generally reflect higher labour escalations compared to 2026 OEB-approved levels as a result of the repeal of the *Protecting a Sustainable Public Sector for Future Generations Act 2019* (“Bill 124”), hiring of additional Nuclear Operators in Training, higher staffing levels to meet regulatory requirements and increased software costs. Nuclear base OM&A costs are presented in Ex. F2-2-1 and Corporate Support Services OM&A costs are presented Ex. F3-1-1.

The DRP reflects the full year impact of the cost of capital and depreciation expense relating to Darlington Unit 4 entering rate base in 2026 (Ex. D2-2-3).

The forecast increase in nuclear fuel costs relative to the OEB-approved level for 2026 reflects higher generation, as discussed above, and higher average nuclear fuel bundle pricing. Nuclear fuel costs are presented in Ex. F2-5-1 and Ex. F2-5-2.

Chart 1: Nuclear Deficiency for 2027 - 2031 Period

Line No		($M) 2027	($M) 2028	($M) 2029	($M) 2030	($M) 2031	Reference
1	**EB-2020-0290 Approved 2026 Revenue Requirement**	**2,439.5**	**2,439.5**	**2,439.5**	**2,439.5**	**2,439.5**	Note 1a
2	Revenue at EB-2020-0290 2026 Payment Amount ($111.33/MWh)	**2,081.0**	**2,971.6**	**2,790.6**	**2,986.3**	**3,222.2**	Note 2a
3	Lower Production (line 1 - line 2)	**358.4**	**(532.1)**	**(351.2)**	**(546.8)**	**(782.8)**	
	Changes in Revenue Requirement:						
4	Pickering Refurbishment Program	411.6	588.3	766.6	898.5	1,213.1	Note 3a
5	Pickering Ongoing Operations	577.3	608.1	644.1	698.6	1,025.9	Note 4a
6	Darlington Outage OM&A Expenses	162.4	51.4	157.8	60.3	54.4	Note 5a
7	Cost of Capital Paramaters	158.1	180.4	189.7	201.8	285.7	Note 6a
8	Darlington Projects	24.0	112.0	148.8	232.1	337.0	Note 7a
9	Other	290.0	277.6	330.0	350.9	381.3	Note 8a
10	**Total Change in Revenue Requirement** (lines 4 through 9)	**1,623.3**	**1,817.8**	**2,237.0**	**2,442.2**	**3,297.4**	
11	**Total Revenue Deficiency** (line 3 + line 10)	**1,981.8**	**1,285.7**	**1,885.8**	**1,895.4**	**2,514.7**	

Notes

1a EB2020-0290 Final Draft Payment Amounts Order Appendix A Table 5, Line 26, col (c)

2a

REDUCED PRODUCTION	**2027**	**2028**	**2029**	**2030**	**2031**
Darlington (Ex. E2-1-1 Table 1, Line 1, cols. (h) to (l))	18.7	26.7	25.1	26.8	27.1
Pickering (Ex. E2-1-1 Table 1, Line 2, cols. (h) to (l))	0.0	0.0	0.0	0.0	1.9
Test Period Production (Ex. E2-1-1 Table 1, line 4, cols. (h) to (l)) **(TWh)**	18.7	26.7	25.1	26.8	28.9
Nuclear Base Payment Amount (Ex. I1-1-2 Table 2, line 4, col. (a)) **($/MWh)**	$111.33	$111.33	$111.33	$111.33	$111.33
Forecast Revenue ($M)	2,081.0	2,971.6	2,790.6	2,986.3	3,222.2

1

Note	Driver of Revenue Requirement Change	EB-2025-0297 (references shown are to EB-2025-0297 exhibits except where noted)		EB-2020-0290 (references shown are to EB-2020-0290 exhibits except where noted)	
3a	**Pickering Refurbishment Program (PRP)**	**PRP revenue requirement impact comprises the sum of:**		*N/A - PRP was not included in EB-2020-0290*	
		OM&A Expenses	Ex. F2-1-1 Table 1a, line 11, cols. (h) to (l)		
		Cost of Capital	Ex. B3-1-1 Table 2, line 6, cols. (f) and (i) and line 18 cols. (c), (f) and (i); Multiplied by: EB-2020-0290 Ex. C1-1-1 Table 1 line 4 col. (b) multiplied by col. (c); Plus: B3-1-1 Table 2, line 6, cols. (f) and (i) and line 18 cols. (c), (f) and (i) Multiplied by: EB 2020-0290 (1 minus Ex. C1-1-1 Table 1 line 4 col. (b)) multiplied by Ex. C1-1-1 Table 1 line 5 col. (c)		
		CCR	Ex. I1-1-1 Table 2 line 22a, cols. (a) to (e)		
		Depreciation	Ex. F4-1-1 Table 2, line 6, cols. (h) to (l)		
4a	**Pickering Ongoing Operations**	**Pickering Ongoing Operations expenses revenue requirement impact comprises of:**		**Pickering Ongoing Operations expenses revenue requirement impact comprises of:**	
		Cyclical OM&A	Ex. F2-1-1 Table 1a line 4, cols. (h) to (l)	Cyclical OM&A	N/A
		Pickering Station Base OM&A	Ex. F2-2-1 Table 1a line 2, cols. (h) to (l)	Pickering Station Base OM&A	Ex. F-2-2-1 Table 1 line 2, col. (k)
		Pickering Station Base OM&A Support	Ex. F2-2-1 Table 1a, Note 2 Pickering NGS, cols. (h) to (l)	Pickering Station Base OM&A Support	Ex. F2-2-1 Table 1, Note 3, Pickering NGS col. (k)
		Pickering Station Base OM&A Corp	Ex. F3-1-1 Table 3b line 10, cols. (h) to (l)	Pickering Station Base OM&A Corp	Ex. F3-1-1 Table 3b line 11, col. (k)
		Centrally Held (GA and Nuclear Insurance)	Ex. F4-4-1 Table 3 Note 1 Pickering NGS, cols. (h) to (l); Plus: F4-4-1 Table 3 Note 2 Pickering NGS, cols. (h) to (l)	Centrally Held (GA and Nuclear Insurance)	N/A
		Outage OM&A	Ex. F2-4-1 Table 1 line 4, cols. (h) to (l)	Outage OM&A	Ex. F-2-4-1 Table 1 line 6, col. (k)
		Project OM&A	Ex. F2-3-1 Table 1 line 2, cols (h) to (l); plus Ex. F2-3-1 Table 1 Note 3 Pickering NGS (allocated + unallocated)	Project OM&A	Ex. F2-3-1 Table 1 line 2, col. (k) Ex. F2-3-1 Table 1 Note 4 Pickering NGS (allocated + unallocated)
		Fuel	Ex. F2-5-1 Table 1a line 2, cols. (h) to (l)	Fuel	Ex. F2-5-1 Table 1 line 2, col (k)
		Property Tax	Ex. F4-2-1 Table 2 line 3, cols. (h) to (l)	Property Tax	Ex. F4-2-1 Table 2 line 3, col (k)
		Depreciation	Ex. F4-1-1 Table 2 line 5, cols. (h) to (l)	Depreciation	Ex. F4-1-1 Table 2 line 4 col (k)
		Cost of Capital	Ex. B3-1-1 Table 2 line 5, cols. (f) and (i) and line 17 cols. (c), (f) and (i); Multiplied by: EB-2020-0290 Ex. C1-1-1 Table 1 line 4 col. (b) multiplied by col. (c); Plus: B3-1-1 Table 2 line 5, cols. (f) and (i) and line 17 cols. (c), (f) and (i) Multiplied by: EB 2020-0290 (1 minus Ex. C1-1-1 Table 1 line 4 (b)) multiplied by Ex. C1-1-1 Table 1 line 5 col. (c)	Refer to EB-2025-0297 description	
5a	**Darlington Outage OM&A Expenses**	**Darlington Outage OM&A expenses revenue requirement impact comprises of:**		**Darlington Outage OM&A expenses revenue requirement impact comprises of:**	
		Outage OM&A	Ex. F2-4-1 Table 1 line 3, cols. (h) to (l)	Outage OM&A	Ex. F2-1-1 Table 1 line 3 col. (k)
6a	**Cost of Capital Parameters**	**Cost of capital revenue requirement impact is calculated as:**		Refer to EB-2025-0297 description	
		Total cost of Capital	Ex. I1-1-1 Table 2 line 14 cols. (a) to (e)		
		Total Capital multiplied by EB-2020-0290 Rate Base Financed by Capital Structure	Less: Ex I1-1-1 Table 2 line 9 cols. (a) to (e) Multiplied by: EB 2020-0290 Ex. C1-1-1 Table 1 line 6 col (c)		
7a	**Darlington Projects**	**Darlington Projects revenue requirement impact comprises of:**		**Darlington Projects revenue requirement impact comprises of:**	
		Cost of Capital	Ex. B3-1-1 Table 2 line 1, cols. (f) and (i) and line 13 cols. (c), (f) and (i); Multiplied by: EB-2020-0290 Ex. C1-1-1 Table 1 line 4 col. (b) multiplied by col (c); Plus B3-1-1 Table 2 line 1, cols. (f) and (i) and line 13 cols. (c), (f) and (i) Multiplied by EB 2020-0290 (1 minus Ex. C1-1-1 Table 1 line 4 col. (b)) multiplied by Ex. C1-1-1 Table 1 line 5 col. (c)	Cost of Capital	Ex. B3-1-1 Table 2 line 9, col. (f) multiplied by Ex. C1-1-1 Table 1 line 4 col. (b) multiplied by col (c); Plus: Ex. B3-1-1 Table 2 line 9, col. (f) multiplied by (1 minus Ex. C1-1-1 Table 1 line 4 col. (b)) multiplied by Ex. C1-1-1 Table 1 line 5 col. (c)
		Depreciation	Ex. F4-1-1 Table 2 line 1, cols. (h) to (l)	Depreciation	Ex B4-1-1 Table 2 line 1 col. (k)
8a	**Other**	**Other revenue requirement impact is calculated as:**		**Other revenue requirement impact is calculated as:**	
		Less: Revenue Requirement Change Factors Identified	As calculated in Notes 3a to 7a	Less: Revenue Requirement Change Factors Identified	As calculated in Notes 3a to 7a

1

DRIVERS OF DEFICIENCY – REGULATED HYDROELECTRIC

1.0 PURPOSE

This evidence presents the major drivers of revenue deficiency for the regulated hydroelectric facilities in 2027 as set out in Ex. I1-1-1, Table 3a.

2.0 OVERVIEW

The revenue deficiency for the regulated hydroelectric facilities in 2027 is primarily driven by higher base OM&A costs due to higher staffing levels to support expanded work programs (Ex. F1-2-1), higher Project OM&A expenditures related to addressing aging assets (as discussed in Ex. F1-3-1), increased cost of capital and depreciation associated with incremental rate base additions (Ex. D1-1-2), and lower income tax expense (Ex. F4-2-1).

The annual revenue deficiency impact of revenue requirement drivers is detailed in Chart 1 and explained in Section 3.0 below.

To determine the revenue deficiency for the regulated hydroelectric facilities, OPG calculated an indicated production revenue for 2027 by multiplying the production forecast in 2027 by the 2026 regulated hydroelectric payment amount resulting from the OEB-approved payment amount in EB-2020-0290. Comparing the indicated production revenue to the annual revenue requirement proposed in this Application shows a revenue deficiency of $243.9M.[1] As the OEB has not approved a revenue requirement for the regulated hydroelectric facilities since EB-2013-0321, it was necessary for OPG to calculate an implied 2026 revenue requirement by cost component. This calculation begins with the EB-2013-0321 approved revenue requirement by cost component (EB-2013-0321, Payment Amounts Order, App. A, Table 1 and EB 2013-0321, Payment Amounts Order, App. A, Table 2) and adjusting income taxes per EB-2016-0152 (Ex. I1-2-1, Table 2). These components were then adjusted by the approved annual adjustments to the payment amounts[2] in the 2017-2021 period. Under O. Reg. 53/05

[1] Chart 1, Line 11.
[2] The OEB approved I-X rates of 1.4% in 2017, 0.9% in 2018, 1.1% in 2019, 1.5% in 2020, and 1.7% in 2021.

section 6(2)13, the OEB-approved 2021 regulated hydroelectric payment amount was then held constant over the 2022-2026 period.

3.0 DRIVERS OF DEFICIENCY FOR THE REGULATED HYDROELECTRIC FACILITIES

3.1 Capital Investments (+60% of revenue deficiency)

The combined impact of return on capital and depreciation from capital investments included in the opening 2027 rate base—when compared to the escalated rate base values approved by the OEB in EB-2013-0321—along with the increase in 2027 capital investments, totals $146.9M. The increase is driven by significant investment made to the regulated hydroelectric aging fleet since EB-2013-0321 to ensure continued safe and effective operations over this period. This includes executing major turbine-generator refurbishments to maintain reliability, redeveloping facilities where appropriate, and undertaking concrete and dam restoration and rehabilitation and other civil infrastructure projects. Refer to Ex. B1-1-1 and Ex. D1-1-2 for further discussion.

3.2 OM&A (+57% of revenue deficiency)

OM&A increases by $140.2M in 2027 reflecting higher Base OM&A costs due to deferred planned maintenance, increased labour costs resulting from *Protecting a Sustainable Public Sector for Future Generations Act, 2019* (Bill 124), and increased resourcing to support the growing work program and regulated hydroelectric project portfolio (Ex. F1-2-1 and Ex. F1-2-2). Project OM&A expenditures are also forecasted to be higher in 2027 primarily relating to overhauls, rehabilitation projects, and concrete repair and restoration projects (Ex. F1-3-1 and Ex. F1-3-2).

3.3 Income Tax Expense (offsets revenue deficiency by 24%)

Income Tax expense decreases in 2027 driven by lower regulatory earnings before tax, along with higher capital cost allowance, reflecting the increase in investments to refresh OPG's

regulated hydroelectric fleet (Ex. F4-2-1). The decrease in income taxes offset the total revenue deficiency by $58.5M.

3.4 Ancillary Revenue and Other (+12% of revenue deficiency)

The forecast of Other Revenues is included as an offset in the calculation of OPG's 2027 revenue requirement for the regulated hydroelectric facilities (Ex. G1-1-1). Period over period historical changes including changes in the 2027 test year are outlined in Ex. G1-1-2. The decrease in Ancillary Revenue and Other is influenced by lower average price spreads impacting Hydroelectric Incentive Mechanism Revenue and lower Ancillary Revenue including Segregated Mode of Operation, Operating Reserve Revenue, Installed Capacity market transactions, and Water Transfer agreements between OPG and the New York Power Authority.

3.5 Gross Revenue Charge ("GRC") (offsets revenue deficiency by 9%)

The GRC is directly dependent on energy production and variances result from production impacts (primarily unit outages, water conditions, and market conditions, see Ex. E1-1-1 and Ex. E1-1-2). The production forecast is inclusive of outages to accommodate the ongoing refurbishment program and other life extension activities across the fleet, and also reflects anticipated energy increases from the refurbishment and redevelopment projects. Variances in GRC for the historical period (2016-2024), bridge period (2025-2026), and test year (2027) are outlined in Ex. F1-4-2. The decrease in GRC costs in the 2027 revenue requirement offset the total revenue deficiency by $22.5M.

3.6 Production (+3% of revenue deficiency)

Production in 2027 of 32.5 TWh is forecasted to decrease by 0.1 TWh relative to the production used in the calculation underpinning the 2026 regulated hydroelectric payment amount. Regulated hydroelectric production is impacted primarily by water availability, unit availability, or a combination thereof. As detailed in Ex. E1-1-1, changes in forecast 2027 production are mainly due to forecast outage differences in forecast production differences expected from refurbishment and redevelopment projects. Refer to Ex. E2-1-2 for further discussion.

Chart 1: Hydroelectric Deficiency for 2027

Line No		($M) 2027	Reference
1	**EB-2020-0290 Approved 2026 Revenue Requirement**	**1,430.7**	Note 1a
2	Revenue at EB-2020-0290_2026 Payment Amount ($43.88/MWh)	**1,424.4**	Note 2a
3	Lower Production (line 1 - line 2)	**6.3**	
	Changes in Revenue Requirement:		
4	OM&A	140.2	Note 3a
5	Capital Investments	146.9	Note 4a
6	Ancillary Revenue and Other	29.9	Note 5a
7	Income Tax	(58.5)	Note 6a
8	GRC	(22.5)	Note 7a
9	Other	1.7	Note 8a
10	**Total Change in Revenue Requirement** (lines 4 through 9)	**237.7**	
11	**Total Revenue Deficiency** (line 3 + line 10)	**243.9**	

Notes

1a EB-2013-0321 Draft Payment Amounts Order Appendix A, Table 1, (line 24, col. (i) / 2)
Plus: (EB-2013-0321 Draft Payment Amounts Order Appendix A, Table 2, (line 24, col. (c) / 2) plus
EB-2013-0321 Draft Payment Amounts Order Appendix A, Table 2, line 24, col (f))) /18 * 12

2a

REDUCED PRODUCTION	**2027**
Test Period Production (Ex. E1-1-1 Table 1, line 4, col. (l)) **(TWh)**	32.5
Hydroelectric Base Payment Amount (Ex. I1-1-2 Table 2, line 1, col. (a)) **($/MWh)**	$43.88
Forecast Revenue ($M)	1,424.4

1

Note	Driver of Revenue Requirement Change	EB-2025-0297	EB-2013-0321 (references shown are to EB-2013-0321 exhibits except where noted)
3a	**OM&A**	EB-2025 Ex. I1-1-1 Table 1 line 13, col .(a)	EB-2013-0321 Draft Payment Amounts Order Appendix A, Table 1, (line 15, col (i) / 2) Plus: [EB-2013-0321 Draft Payment Amounts Order Appendix A, Table 2, (line 15, col (c) / 2) plus EB-2013-0321 Draft Payment Amounts Order Appendix A, Table 2, line 15, col (f)] /18 * 12) Multplied by: (1+ EB-2016-0152 Final Draft Payment Amounts Order, Appendix B, Table 1, (line 4, col. (a) Multplied by: (1+ EB-2016-0152 Final Draft Payment Amounts Order, Appendix B, Table 1, (line 4, col. (b) Multplied by: (1+ EB-2018-0243, Page 3: 1.1%) Multplied by: (1+ EB-2019-0209, Page 3: 1.5%) Multplied by: (1+ EB-2020-0210, Page 3: 1.7%)
4a	**Capital Investments**	Ex. I1-1-1 Table 1 line 15, col .(a) plus EB-2025 Ex. I1-1-1 Table 1 line 12, col .(a)	EB-2013-0321 Draft Payment Amounts Order Appendix A, Table 1, ((line 14 + line 17), col (i) / 2) Plus: [EB-2013-0321 Draft Payment Amounts Order Appendix A, Table 2, (line 14 + line 17) , col (c) / 2) plus EB-2013-0321 Draft Payment Amounts Order Appendix A, Table 2, (line 14 + line 17), col (f)] /18 * 12) Multiplied by: (1+ EB-2016-0152 Final Draft Payment Amounts Order, Appendix B, Table 1, (line 4, col. (a) Multiplied by: (1+ EB-2016-0152 Final Draft Payment Amounts Order, Appendix B, Table 1, (line 4, col. (b) Multiplied by: (1+ EB-2018-0243, Page 3: 1.1%) Multiplied by: (1+ EB-2019-0209, Page 3: 1.5%) Multiplied by: (1+ EB-2020-0210, Page 3: 1.7%)
5a	**Ancillary Revenue and Other**	Ex. I1-1-1 Table 1 line 18, col .(a)	EB-2013-0321 Draft Payment Amounts Order Appendix A, Table 1, (line 21, col (i) / 2) Plus: [EB-2013-0321 Draft Payment Amounts Order Appendix A, Table 2, (line 21, col (c) / 2) + EB-2013-0321 Draft Payment Amounts Order Appendix A, Table 2, line 21, col (f)] /18 * 12) Multiplied by: (1+ EB-2016-0152 Final Draft Payment Amounts Order, Appendix B, Table 1, (line 4, col. (a) Multiplied by: (1+ EB-2016-0152 Final Draft Payment Amounts Order, Appendix B, Table 1, (line 4, col. (b) Multiplied by: (1+ EB-2018-0243, Page 3: 1.1%) Multiplied by: (1+ EB-2019-0209, Page 3: 1.5%) Multiplied by: (1+ EB-2020-0210, Page 3: 1.7%)
6a	**Income Tax**	Ex. I1-1-1 Table 1 line 20, col .(a)	EB-2013-0321 Draft Payment Amounts Order Appendix A, Table 1, (line 23, col (i) / 2) Plus: [EB-2013-0321 Draft Payment Amounts Order Appendix A, Table 2, (line 23, col (c) / 2) + EB-2013-0321 Draft Payment Amounts Order Appendix A, Table 2, line 23, col (f)] /18 * 12) Plus: (EB2016-0152 (Ex. I1-2-1, Table 2, line 1 (col. b) / 2) plus (EB2016-0152 (Ex. I1-2-1, Table 2, line 4 (col. b) / 18 * 12) Multiplied by: (1+ EB-2016-0152 Final Draft Payment Amounts Order, Appendix B, Table 1, (line 4, col. (a))) Multiplied by: (1+ EB-2016-0152 Final Draft Payment Amounts Order, Appendix B, Table 1, (line 4, col. (b))) Multiplied by: (1+ EB-2018-0243, Page 3: 1.1%) Multiplied by: (1+ EB-2019-0209, Page 3: 1.5%) Multiplied by: (1+ EB-2020-0210, Page 3: 1.7%)
7a	**GRC**	Ex. I1-1-1 Table 1 line 14, col .(a)	EB-2013-0321 Draft Payment Amounts Order Appendix A, Table 1, (line 16, col (i) / 2) Plus: [EB-2013-0321 Draft Payment Amounts Order Appendix A, Table 2, (line 16, col (c) / 2) plus EB-2013-0321 Draft Payment Amounts Order Appendix A, Table 2, line 16, col (f)] /18 * 12) Multiplied by: (1+ EB-2016-0152 Final Draft Payment Amounts Order, Appendix B, Table 1, (line 4, col. (a) Multiplied by: (1+ EB-2016-0152 Final Draft Payment Amounts Order, Appendix B, Table 1, (line 4, col. (b) Multiplied by: (1+ EB-2018-0243, Page 3: 1.1%) Multiplied by: (1+ EB-2019-0209, Page 3: 1.5%) Multiplied by: (1+ EB-2020-0210, Page 3: 1.7%)
8a	**Other**	Ex. I1-1-1 Table 1 line 16, col .(a)	EB-2013-0321 Draft Payment Amounts Order Appendix A, Table 1, (line 18, col (i) / 2) Plus: [EB-2013-0321 Draft Payment Amounts Order Appendix A, Table 2, (line 18, col (c) / 2) + EB-2013-0321 Draft Payment Amounts Order Appendix A, Table 2, line 18, col (f)] /18 * 12) Multiplied by: (1+ EB-2016-0152 Final Draft Payment Amounts Order, Appendix B, Table 1, (line 4, col. (a) Multiplied by: (1+ EB-2016-0152 Final Draft Payment Amounts Order, Appendix B, Table 1, (line 4, col. (b) Multiplied by: (1+ EB-2018-0243, Page 3: 1.1%) Multiplied by: (1+ EB-2019-0209, Page 3: 1.5%) Multiplied by: (1+ EB-2020-0210, Page 3: 1.7%)

1

OVERVIEW OF OPG

1.0 PURPOSE

This evidence provides an overview of OPG, including a summary of its mandate, objectives, key assets, corporate governance and organization. OPG's regulated hydroelectric and nuclear businesses are described in Ex. A1-4-2 and Ex. A1-4-3, respectively. Information about DNNP LP, including DNNP facilities, is set out separately in Ex. A1-4-4.

2.0 CORPORATE OVERVIEW

OPG is an electricity generation company whose principal business is the generation and sale of electricity. As the province's largest electricity producer, OPG is focused on the effective stewardship of generation assets owned by the people of Ontario. This is achieved by focusing on: (i) the safe, reliable operation of its facilities including the avoidance of harm to employees, contractors, and the public at large, (ii) the management of these facilities by maintaining a strong focus on delivering value for money, and (iii) adhering to the highest standards of corporate citizenship, including environmental and social objectives.

As part of its business, OPG owns and operates both regulated and unregulated generation facilities. OPG's active regulated generation facilities in Ontario consist of two nuclear generating stations, the Darlington Nuclear Generating Station and the Pickering Nuclear Generating Station, with a total generation capacity of 5,576 MW[1] and 54 regulated hydroelectric generating stations with a total generation capacity of 6,566 MW, for a combined regulated generation capacity of 12,142 MW.

While not regulated facilities, the Bruce A and B Nuclear Generating Stations in Ontario have an impact on the calculation of the payment amounts. These stations are owned by OPG and leased on a long-term basis to Bruce Power L.P.

[1] Pickering Units 5-8 have a net in-service capacity of 2,064 MW, and Darlington Units 1-4 have an in-service capacity of 3,512 MW including units undergoing refurbishment.

The locations of both the regulated facilities and other OPG facilities are illustrated on the map provided as Attachment 1.

In 2024, OPG's regulated facilities generated a total of 65.5 TWh. The regulated hydroelectric facilities generated 32.5 TWh and the nuclear facilities generated 33 TWh.

3.0 OPG GOVERNANCE AND ORGANIZATION

OPG's Board of Directors ("OPG Board") is appointed by His Majesty the King in right of Ontario as represented by the Minister of Energy and Mines (the "Shareholder"). All of OPG's directors are independent of the company except for the OPG President and Chief Executive Officer ("CEO") and Bill Pitesa.[2] The members of the OPG Board bring substantial expertise in commercial leadership; managing and operating nuclear generator operations; understanding of the Canadian nuclear environment; engineering and project management, including large infrastructure project management; managing large capital intensive industrial operations; knowledge and expertise in business growth strategy and transformation, including mergers and acquisitions; overseeing regulatory, government and public relations; executive compensation and human capital management; financial, risk management, investment, health and safety, supply chain and corporate governance expertise; sustainability and environmental, social and governance experience; expertise in information technology/cybersecurity; knowledge of and experience with Indigenous communities; and stakeholder management.

The OPG Board has established the following committees to focus on areas critical to OPG's success:

- **Audit and Risk Committee:** The Audit and Risk Committee is responsible for the integrity, quality and transparency of OPG's financial information, the adequacy of the financial reporting process, the systems of internal controls, and OPG's related principles, policies and procedures which management has established. The Committee is responsible for the oversight of the Company's regulatory filings including financial statements and

[2] Mr. Pitesa was previously the Chair of the Nuclear Safety Review Board, which was a review board independent of management.

Management's Discussion & Analysis and other disclosures. The Committee also provides oversight of the performance of the OPG Pension Fund, the Used Fuel Segregated Fund, and the Decommissioning Segregated Fund. Additionally, the Committee is responsible for the oversight of enterprise-wide risk and associated risk management activities, including the review of management's assessment of the principal risks to achieving the Company's objectives. The Committee is also responsible for ensuring that an effective Code of Conduct is in place at OPG and monitors compliance with this code.

- **Human Resources and Governance Committee:** The Human Resources and Governance Committee provides oversight of OPG's human resources and compensation policies and practices, including CEO objectives and compensation, disclosure on compensation and human resources matters, organizational culture, leadership talent review, succession planning and collective bargaining. The Committee also oversees the design of OPG's benefit and pension plans and reviews reports from the Chief Ethics Officer on matters that involve Code of Business Conduct violations and compliance which are primarily personnel related. The Human Resources and Governance Committee oversees the Board's governance program and practices to ensure that they are consistent with high standards of corporate governance, including annually reviewing and assessing the Board's system of corporate governance with a view to maintaining these high standards.

- **Generation Oversight Committee:** The Generation Oversight Committee is responsible for the oversight of safe, secure and efficient operations of OPG's generating facilities. Additionally, the Committee oversees the development, risk management, financing and execution of OPG's generation projects greater than $100M, with certain exclusions. This Committee also is responsible for providing oversight for matters relating to business development and business acquisitions, and is also responsible for the oversight of OPG's environmental and dam safety management systems and OPG's Indigenous relations. The Committee also reviews the results of assessments in respect of OPG's generation operations by advisors and independent oversight organizations. The Committee provides

oversight to help ensure that OPG's generating facilities comply with nuclear safety, industrial and occupational health and safety, and environmental laws and regulations.

- **Major Projects Committee:** The Major Projects Committee is responsible for the oversight of the execution of major projects greater than $500M, including the Darlington and Pickering Refurbishment projects (the "Refurbishment Projects") and the Darlington New Nuclear Project, that are undertaken by the Company through the internal Enterprise Projects Office organization as may be determined from time to time, and monitors the progress of the refurbishment program against the approved budget and schedule. The Committee is also responsible for reviewing and approving the retention and compensation of qualified advisors, independent of OPG management, to monitor and report to the Committee on the progress and performance of such major projects against approved execution plans, including scopes, budgets and schedules. The Committee monitors and reports to the OPG Board on the progress of the major projects including the Refurbishment Projects against the Board approved budgets and schedules, reviews reports from OPG's Vice President, Risk & Audit and Chief Audit Executive and reviews results of internal assessments and management's response to the findings of such assessments.

OPG is led by the Enterprise Leadership Team, which is comprised of senior management members from across the organization and the President and CEO, who is also a member of the OPG Board.

OPG's nuclear and renewable generation business units and centralized operations support groups are led by a single Enterprise Operations organization. OPG's Enterprise Projects Organization is responsible for all major project planning and execution, including oversight of the DNNP and the refurbishment of the Darlington, Pickering and Renewable Generation stations. Enterprise Operations and Enterprise Projects report directly to the President and CEO. Strategy planning and execution responsibilities across the company are under the Enterprise Strategy and New Nuclear organization.

Renewable Generation operations includes regulated and unregulated hydroelectric operations, and other non-nuclear unregulated operations.

The organization and management of the regulated hydroelectric facilities and the nuclear facilities are described in greater detail in Ex. A1-4-2 and Ex. A1-4-3, respectively.

Also reporting directly to the President and CEO are the various functions that provide support to Enterprise Operations, Enterprise Projects and Enterprise Strategy. These include the Corporate Services Office (which includes Human Resources, Corporate & Technology Services, and New Growth and Business Development), Finance, Treasury, Assurance, and Commercial Integration and Strategy. These functions are described in greater detail in Ex. F3-1-1, Attachment 1.

Certain of OPG's unregulated businesses are owned and operated through separate subsidiaries, including Atura Power, Laurentis Energy Partners, and Eagle Creek Renewable Energy.[3] These subsidiaries have their own management teams, which are overseen by certain of OPG's senior executives in their roles as corporate directors of the subsidiaries.

A summarized overview of OPG's organizational chart is provided in Ex. A1-5-1. A description of the normalization completed for organizational changes since EB-2020-0290 is provided in Attachment 2.

OPG's Board policies are published on the company's website at https://www.opg.com/about-us/governance-regulation/committees-policies/. The Board policies are:

- Code of Business Conduct Policy
- Conflict of Interest Policy
- Cyber Security Policy
- Delegation and Exercise of Authority Policy
- Disclosure Policy

[3] In October 2025, OPG entered into an agreement for the sale of Eagle Creek Renewable Energy, which OPG expects to close in 2026.

- Indigenous Relations Policy
- Employee Health and Safety Policy
- Enterprise Risk Management Policy
- Environmental Policy
- Nuclear Safety Policy
- OPG Board Diversity and Inclusion Policy
- Safe Operations Policy

4.0 OPG'S MANDATE AND OBJECTIVES

OPG is party to a Memorandum of Agreement with the Shareholder, dated September 3, 2021, (the "Memorandum of Agreement"), which serves as the basis of agreement between OPG and its Shareholder, the Province of Ontario, on the mandate, governance, performance, and communications of OPG. The purposes of the Memorandum of Agreement include the promotion of a positive and co-operative working relationship between OPG and its Shareholder. The Memorandum of Agreement also establishes the accountabilities and relationships solely between OPG and the Shareholder and provides that in its discretion, the Shareholder may waive or deem compliance of OPG's obligations as appropriate in the circumstances.

The Memorandum of Agreement confirms that OPG will operate as a business enterprise with a commercial mandate, governed in principle and at first instance by an independent Board of Directors which directors are charged with the fiduciary duty to act honestly and in good faith with a view to the best interests of OPG. The OPG Board is responsible for appointing the OPG President and CEO who, along with OPG management, is responsible for the day-to-day operations of OPG.

The Memorandum of Agreement further states that the Shareholder may at times direct OPG to undertake special initiatives, which will be communicated as written declarations by way of a Unanimous Shareholder Agreement, or Declaration, in accordance with Section 108 of the *Business Corporations Act* (Ontario) and made public. Copies of the Shareholder directives that OPG has received are posted on OPG's website at:

http://www.opg.com/about/management/open-and-accountable/Pages/shareholder-directives.aspx.

The Memorandum of Agreement is provided as Attachment 3.

5.0 INTERNAL AUDIT – COMPLETED ENGAGEMENTS SINCE Q4 2020

Consistent with the OEB-approved settlement proposal in EB-2020-0290, Attachment 4 is a listing and summary of the non-solicitor-client privileged internal audits completed subsequent to those listed in EB-2020-0290, Ex. L-A1-02-SEC-011, Attachment 1. Audits pertaining exclusively to OPG's non-regulated business are not included.

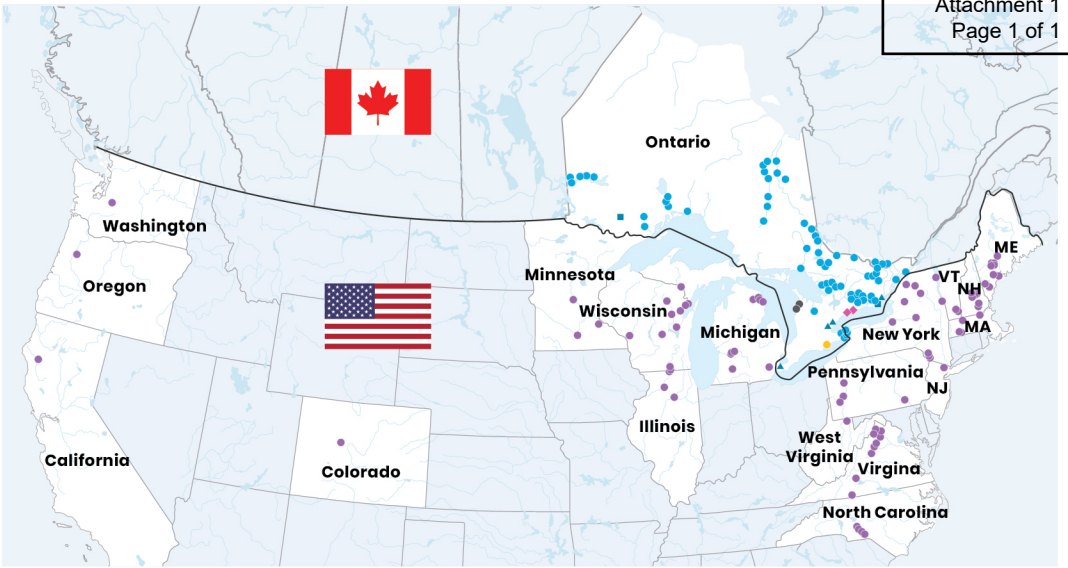
LIST OF ATTACHMENTS

Attachment 1: Map showing locations of OPG facilities

Attachment 2: Normalization of Organizational Changes

Attachment 3: Memorandum of Agreement between the Shareholder and OPG

Attachment 4: Summaries of Internal Audits Completed Since Q4 2020



2	2	2	1	66	85	4
Nuclear Stations	Leased **Nuclear** Stations	**Thermal** Stations	**Solar** Facility	**Canada Hydroelectric** Stations	**US Hydroelectric** Stations	**Atura Power Gas-Fired** Stations

NORMALIZATION FOR ORGANIZATIONAL CHANGES

This evidence summarizes organizational changes within OPG since the OEB's Decision and Order in EB-2020-0290. To provide comparability between actual, budget, OEB-approved (EB-2020-0290) and IR term/forecast period amounts, OPG has restated the cost information affected by organizational changes and recategorization of costs as appropriate. The major changes captured by this restatement include:

Station and Operations and Project Support

- Enterprise Engineering – now includes Enterprise Innovation, Data Analytics and Asset Management, which were previously part of Integrated Fleet Management.
- Integrated Fleet Management – now includes the Security and Training organizations and part of the Radiation Safety organization, which was previously part of Station Site and Support Services.
- Environment Health & Safety - now part of Enterprise Operations to better support operational safety and excellence. Health Services, which was a component of the broader Environment, Health & Safety organization, is now part of Human Resources.
- Other Operations Support - now includes Nuclear Regulatory Affairs and Nuclear Oversight, which were previously within Integrated Fleet Management. Additionally, Model Development and Analysis (previously within Corporate Centre) and Generation and Revenue Planning (previously within Finance), are now under Other Operations Support.
- Renewable Generation Stations were reorganized into three regions (Niagara, Eastern and Western).

Support Services

- The Chief Administration Office umbrella organization was reorganized into the Corporate Services umbrella organization to include Finance in addition to the continuing to hold the Human Resources, Corporate & Technology Services ("C&TS") (formerly known as Chief Information Office) and Real Estate. Supply Chain, Commercial Management (formerly in

Enterprise Projects) and Regulatory Affairs were combined into a new umbrella organization, Commercial Operations & Regulatory Affairs.[1]

- Real Estate - now includes Corporate Communications, which was previously part of Corporate Centre.
- Human Resources - now includes Ethics and Equity, which was previously part of Corporate Centre.

The current structure of OPG's nuclear operations functions is described in detail in Ex. F2-2-1, Attachment 1, Renewable Generation RG operations in Ex. F1-2-1, Attachment 1 and Support Services in Ex. F3-1-1, Attachment 1.

To provide a consistent basis for comparison, the tables throughout this Application present OPG's historical and bridge period costs, on a normalized basis that reflects the current organizational structure.

Charts 1, 2, and 3 below illustrate the movement of costs between the Nuclear facilities' OM&A cost categories over the 2022-2026 period for OEB approved amounts. Chart 1 provides the OEB approved amounts consistent with the original presentation in the EB-2020-0290 application. Chart 2 provides the same forecast costs mapped to OPG's current organizational structure and cost categories. Chart 3 summarizes the net change in each cost category between Chart 1 and Chart 2.

Historical Nuclear facilities' OM&A costs in this Application are presented consistent with Chart 2.

[1] Human Resources, Finance, Supply Chain, and C&TS functions continue to be separately presented in Ex. F3-1-1 and Ex. F3-1-2. Commercial Management and Regulatory Affairs are included within Corporate Centre in Ex. F3-1-1 and Ex. F3-1-2.

Chart 1 - Nuclear Operating Costs per EB-2020-0290 Payment Amounts Order

Line No.	Cost Item	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan
	OM&A:					
1	OPG Nuclear Facilities Base OM&A	1,283.0	1,273.9	1,259.2	1,037.5	597.8
2	OPG Nuclear Facilities Project OM&A	86.4	82.5	78.2	74.4	60.1
3	OPG Nuclear Facilities Outage OM&A	270.7	350.4	206.0	186.8	59.5
4	Pickering Cyclical Maintenance OM&A	-	-	-	-	-
5	**Subtotal OPG Nuclear Facilities OM&A[1]**	**1,640.1**	**1,706.7**	**1,543.4**	**1,298.6**	**717.5**
6	Darlington Refurbishment OM&A	24.2	23.6	29.3	25.0	8.4
7	Darlington New Nuclear OM&A	2.2	2.2	2.3	2.3	2.3
8	DNNP Operational Readiness	-	-	-	-	-
9	Other New Nuclear OM&A	-	-	-	-	-
10	Pickering Refurbishment Feasibility Study	-	-	-	-	-
11	Pickering Refurbishment OM&A	-	-	-	-	-
12	Allocation of Corporate Costs[1]	376.0	368.3	363.5	327.0	248.1
13	Allocation of Centrally Held Costs	184.5	161.6	143.9	98.9	14.7
14	Asset Service Fees[1,2]	49.2	52.6	54.6	51.4	47.8
15	**Subtotal Other OM&A**	**636.1**	**608.3**	**593.6**	**504.6**	**321.4**
16	**Total OPG Nuclear Facilities OM&A**	**2,276.2**	**2,315.0**	**2,137.0**	**1,803.3**	**1,038.9**

1 Per EB-2020-0290 OEB Decision and Order, Schedule A, p. 25, OM&A costs are reduced by 3% per year over the 2022-2026 period.

2 OEB approved values reflect settlement adjustments for Clarington Corporate Campus (2024-2026) per p. 25 of the Settlement Proposal.

Chart 2 - EB-2020-0290 Planned Nuclear Operating Costs per Current Structure

Line No.	Cost Item	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan
	OM&A:					
1	OPG Nuclear Facilities Base OM&A	1,294.0	1,284.8	1,271.8	1,047.6	603.0
2	OPG Nuclear Facilities Project OM&A	86.4	82.5	76.6	72.8	60.1
3	OPG Nuclear Facilities Outage OM&A	270.7	350.4	206.0	186.8	59.5
4	Pickering Cyclical Maintenance OM&A					
5	**Subtotal OPG Nuclear Facilities OM&A[1]**	**1,651.1**	**1,717.7**	**1,554.5**	**1,307.2**	**722.6**
6	Darlington Refurbishment OM&A	24.2	23.6	29.3	25.0	8.4
7	Darlington New Nuclear OM&A	2.2	2.2	2.3	2.3	2.3
8	DNNP Operational Readiness	-	-	-	-	-
9	Other New Nuclear OM&A	-	-	-	-	-
10	Pickering Refurbishment Feasibility Study	-	-	-	-	-
11	Pickering Refurbishment OM&A	-	-	-	-	-
12	Allocation of Corporate Costs[1]	365.0	356.7	347.9	314.7	242.9
13	Allocation of Centrally Held Costs	184.5	162.2	148.5	102.7	14.7
14	Asset Service Fees[1,2]	49.2	52.6	54.6	51.4	47.8
15	**Subtotal Other OM&A**	**625.1**	**597.4**	**582.5**	**496.1**	**316.2**
16	**Total OPG Nuclear Facilities OM&A**	**2,276.2**	**2,315.0**	**2,137.0**	**1,803.3**	**1,038.9**

1 Per EB-2020-0290 OEB Decision and Order, Schedule A, p. 25, OM&A costs are reduced by 3% per year over the 2022-2026 period.

2 OEB approved values reflect settlement adjustments for Clarington Corporate Campus (2024-2026) per p. 25 of the Settlement Proposal.

Chart 3 - Net Change in Cost Items

Line No.	Cost Item	2022 Plan	2023 Plan	2024 Plan	2025 Plan	2026 Plan
	OM&A:					
1	OPG Nuclear Facilities Base OM&A	11.0	11.0	12.6	10.1	5.2
2	OPG Nuclear Facilities Project OM&A	0.0	0.0	(1.6)	(1.6)	0.0
3	OPG Nuclear Facilities Outage OM&A	(0.0)	0.0	0.0	0.0	0.0
4	Pickering Cyclical Maintenance OM&A	0.0	0.0	0.0	0.0	0.0
5	**Subtotal OPG Nuclear Facilities OM&A[1]**	**11.0**	**11.0**	**11.0**	**8.5**	**5.2**
6	Darlington Refurbishment OM&A	0.0	0.0	(0.0)	0.0	0.0
7	Darlington New Nuclear OM&A	0.0	0.0	0.0	0.0	0.0
8	DNNP Operational Readiness	0.0	0.0	0.0	0.0	0.0
9	Other New Nuclear OM&A	0.0	0.0	0.0	0.0	0.0
10	Pickering Refurbishment Feasibility Study	0.0	0.0	0.0	0.0	0.0
11	Pickering Refurbishment OM&A	0.0	0.0	0.0	0.0	0.0
12	Allocation of Corporate Costs[1]	(11.0)	(11.6)	(15.5)	(12.3)	(5.2)
13	Allocation of Centrally Held Costs	0.0	0.6	4.6	3.8	0.0
14	Asset Service Fees[1,2]	0.0	0.0	(0.0)	(0.0)	0.0
15	**Subtotal Other OM&A**	**(11.0)**	**(11.0)**	**(11.0)**	**(8.6)**	**(5.2)**
16	**Total OPG Nuclear Facilities OM&A**	**0.0**	**0.0**	**(0.0)**	**(0.0)**	**0.0**

1 Per EB-2020-0290 OEB Decision and Order, Schedule A, p. 25, OM&A costs are reduced by 3% per year over the 2022-2026 period.

2 OEB approved values reflect settlement adjustments for Clarington Corporate Campus (2024-2026) per p. 25 of the Settlement Proposal.

MEMORANDUM OF AGREEMENT

BETWEEN

Her Majesty the Queen in right of Ontario, as represented by the Minister of Energy (the "Shareholder" or “Minister”)

And

Ontario Power Generation, Inc. ("OPG")

MEMORANDUM OF AGREEMENT

BETWEEN
Her Majesty the Queen in right of Ontario as represented by the Minister of Energy (the "Shareholder" or “Minister)
And
Ontario Power Generation, Inc. ("OPG") or the “Corporation”

WHEREAS OPG is a business corporation incorporated under the *Business Corporations Act* (Ontario)

AND WHEREAS The Minister, on behalf of Her Majesty in right of Ontario, may acquire and hold shares of OPG, and has primary policy responsibility for the overall legislative and regulatory framework, established primarily under the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998,* and the applicable regulations, within which OPG must conduct its business operations.

NOW THEREFORE the parties hereto have agreed as follows.

1 DEFINITIONS/INTERPRETATION

1.1 The following terms shall have the meanings ascribed to them herein:

“Corporation” means “Ontario Power Generation Inc.”

“EA” means the *Electricity Act, 1998* (Ontario) and its regulations.

“Deputy Minister” means the Deputy Minister of Energy, a public servant appointed by the Lieutenant Governor in Council under the auspices of section 4 of the *Ministry of Energy Act, 2011*(Ontario)*;*

“Ministry means the ministry of the Minister;

“Minister” means the Minister of Energy, appointed by the Lieutenant Governor in Council under the auspices of the *Executive Council Act* (Ontario) and includes reference to such other member of the Executive Council as may be assigned the administration of the *Ministry of Energy Act, 2011* (Ontario) under the *Executive Council Act* (Ontario);

“MOA” means this Memorandum of Agreement, including any and all appendixes attached hereto;

“OBCA” means *Business Corporations Act* (Ontario);

"OEBA" means the *Ontario Energy Board Act, 1998* (Ontario) and its regulations, codes, or orders of the Ontario Energy Board, as applicable*;*

"OPG Board Chair" means the member of the Corporation's Board of Directors which is appointed by the Minister pursuant to a unanimous shareholder resolution made in writing, and who is designated by the Minister as Chair;

"Shareholder" means Her Majesty the Queen, in Right of the Province of Ontario, as represented by the Minister who holds all of the issued shares of the Corporation on behalf of the Crown, and "sole shareholder" shall have the same meaning.

2. PURPOSE OF THIS MEMORANDUM OF AGREEMENT

The parties hereto agree and acknowledge that the purpose of this MOA is as set out below:

2.1 To serve as the basis of agreement between OPG and its sole Shareholder on mandate, governance, performance, and communications of OPG.

2.2 To establish the accountabilities and relationships solely between OPG and the Shareholder. In its discretion, the Shareholder may waive or deem compliance of OPG's obligations as appropriate in the circumstances.

2.3 To promote a positive and co-operative working relationship between OPG and the Shareholder.

3 GOVERNANCE OF OPG

3.1 Under the OBCA, the OPG Board of Directors is responsible for supervising the management of the business affairs and operations of the Corporation, including a fiduciary duty to act honestly and in good faith with a view to the best interests of the Corporation and to exercise the skill as well as a standard of care and diligence that a reasonably prudent person would exercise in similar circumstances. As such, the Corporation operates as a business enterprise with a commercial mandate, governed in principle and at first instance by an independent Board of Directors who is responsible for the appointment of the President and Chief Executive Officer. The President and Chief Executive Officer and management are responsible for the day-to-day operations of the Corporation.

3.2 The Minister shall be responsible for appointing or re-appointing, in a timely manner and following consultation with the Chair, as appropriate, the directors of OPG pursuant to the

process established by the Public Appointments Secretariat and securities regulators' National Policy on Corporate Governance Guidelines.

3.3 As a reporting issuer of debt securities, OPG is subject to the disclosure standards and requirements of the *Securities Act* (Ontario) and shall make such disclosures as may be required.

3.4 As set out in subsection 53.1(2) of the EA, OPG and its subsidiaries are not agents of the Crown for any purpose, despite the *Crown Agency Act* (Ontario).

3.5 OPG shall operate in an accountable and transparent manner with regard to the Corporation's governance, management, administration and operations. In this regard, OPG is subject to a number of statutes and Treasury Board/Management Board of Cabinet directives. A list of applicable statutes and directives is set out in Appendix 1 and Appendix 2 attached hereto.

3.6 Notwithstanding the foregoing, the Shareholder may at times direct OPG to undertake special initiatives. Any such direction shall be written declaration by way of a Unanimous Shareholder Agreement and/or declarations and resolutions, in accordance with the OBCA, which shall be made public by OPG within a reasonable timeframe by publishing such agreements, declarations and resolutions on the Corporation's website.

3.7 Unless otherwise directed by the Shareholder or statute, OPG shall operate in Ontario in accordance with the highest corporate standards, including but not limited to the highest corporate standards in the areas of corporate governance and social responsibility. OPG shall continue to benchmark its corporate governance practices against the securities regulators' National Policy on Corporate Governance Guidelines, as well as other leading governance organizations, as appropriate.

3.8 OPG shall comply with the *Accessibility for Ontarians with Disabilities Act.*

4 MANDATE

4.1 The objects of OPG include, in addition to any other objects, owning and operating a diversified portfolio of electricity and generation assets and providing related services.

4.2 OPG shall leverage its assets and expertise to generate new revenues on a commercially sound basis, including the making of strategic investments and acquisitions and related business opportunities in the electricity sector both inside and outside Ontario, on its own or in partnership as appropriate, for the benefit of the Corporation and the Shareholder.

4.3 OPG shall continue to operate as a respected, publicly-owned electricity generation enterprise and to operate its assets efficiently and cost-effectively, and to deliver value to Ontario 's ratepayers and taxpayers.

4.4 OPG shall ensure that it conducts its operations in full compliance with all laws and regulations and strives to serve as a model in regard to public and employee safety, environmental practices, corporate citizenship, community engagement and relations with Indigenous communities and peoples.

4.5 OPG shall undertake generation development projects in support of the Province's energy planning priorities and initiatives, as may be updated from time to time.

4.6 OPG shall support the Province of Ontario's efforts to fulfill the Crown's constitutional duty to consult and accommodate Indigenous peoples, where that duty arises in relation to OPG generation or other projects, by carrying out those procedural aspects of the Crown's consultation obligations that are delegated in writing to OPG by the Province, including the Ministry.

4.7 The Province of Ontario and the Ministry supports the role of public power and mitigating electricity prices in Ontario and in doing so:

a. mandates that OPG maintain itself as a strong, viable public power component of the electricity sector at an appropriate scale and with electricity and generation portfolio diversity to ensure long-term operational and financial sustainability and to support OPG long term liabilities, including by increasing the output of, refurbishing or adding operating capacity to, existing generation facilities consistent with the Province's energy planning priorities and initiatives; and

b. mandates that OPG plan and operate its electricity and generation facilities based upon good utility practice recognizing safety, legal, regulatory, environmental and market factors.

4.8 OPG shall support the Province's economic development objectives where feasible, including generating financial benefits that accrue to the Province of Ontario and remain within the Province of Ontario.

4.9 OPG shall serve the public interest and operate in a way that achieves a commercial rate of return, moderates overall electricity prices, and supports the efficient operation of the electricity market.

4.10 OPG shall earn a commercial rate of return and generate sufficient returns to support and service its borrowing needs for operations, projects, and investments; as well as supporting the opportunity to access public debt markets in the future. Any significant new electricity or

generation assets approved by the Board of Directors, and as agreed to by the Shareholder, may receive financial support from the Province of Ontario, if and as appropriate.

4.11 Subject to any unanimous shareholder declaration or resolution, OPG shall be permitted to participate in all energy-related procurements in Ontario that it meets the qualifications for.

4.12 In addition to the requirements of section 5.1, OPG shall inform the Shareholder in advance of any new generation development projects (not upgrades or redevelopments) the Corporation intends to undertake or assume.

4.13 Where appropriate, OPG shall pursue prospective generation related developments with Indigenous communities that can provide the basis for long term mutually beneficial commercial arrangements.

4.14 Acknowledging sections 3.1 and 3.4 of this MOA, OPG will act in the interests of both OPG and the Shareholder in entering into potential settlements of Indigenous peoples' claims or grievances or arrangements with communities potentially affected by OPG generation development. Unless otherwise agreed to with the Shareholder, OPG will pursue such agreements or arrangements so that the Shareholder benefits equally from releases from liability and indemnifications obtained by OPG in relation to damage caused by the construction, operation and development of OPG facilities. Nothing in this MOA will require OPG to pursue releases for matters for which the Shareholder may be solely liable.

4.15 OPG may request that the Ministry seek Treasury Board/Management Board of Cabinet approval for special status for international travel under the Travel, Meal and Hospitality Directive. OPG will not seek special status to serve alcohol under this Directive.

5 REPORTING REQUIREMENTS

5.1 OPG and the Shareholder will ensure timely sharing of information on major developments and issues that may impact the business of OPG or the interests of the Shareholder. Major developments and issues include planned acquisition of energy assets, assumption of existing power supply contracts, proposed settlements of Indigenous peoples' claims or grievances relating to OPG facilities, and proposed arrangements with communities affected by OPG generation development. OPG and the Shareholder will follow the guidance of any agreed upon framework for acquisitions.

5.2 OPG shall report to the Shareholder, on an immediate basis, where human safety or system reliability issues arise.

5.3 Every year OPG shall develop and submit a rolling multi-year business plan to the Shareholder for review and concurrence. Business plans will cover a minimum period of three years.

a. Once approved by OPG's Board of Directors, OPG's annual business plan will be submitted to the Minister for concurrence.

b. The annual business plan shall include multi-year performance targets based on operating and financial results as well as major project execution. It shall also include a multi-year investment plan for new projects.

c. OPG shall include objectives for operational efficiency improvements in its business plan.

d. Staff from the Ministry will review OPG's annual business plan in a timely manner.

e. The Deputy Minister shall advise and assist the Minister on any responsibilities associated with the approval of OPG's annual business plan.

f. OPG shall respond to any comments or requests for further information on the annual business plan, made by the Minister, Deputy Minister or Ministry staff in a timely manner.

g. Concurrence by the Minister will be subject to the presentation of OPG's business plan before Treasury Board.

h. Minister's concurrence may outline expectations for OPG's next business plan. OPG's next business plan will identify how it addresses the Minister's expectations from the previous year.

i. OPG shall provide, in a timely manner, updates on quarterly performance against business plan projections for the Minister's review.

5.4 Within 90 days after the end of each fiscal year, as required by subsection of 53.4 (1) of the EA, OPG shall submit to the Minister an annual report on its affairs during that fiscal year.

a. In a timely manner in advance of the submission of the annual report to the Minister, OPG will provide a draft copy of the annual report for Ministry staff to review.

b. Ministry staff will review the draft annual report in a timely manner, and may request additional information from OPG, as necessary.

5.5 OPG shall provide, in a timely manner, quarterly and year-end financial reports for the Ministry's review prior to filing with the Ontario Securities Commission, and in particular:

a. year-end financials, which include News Release, MD&A and Audited Financial Statements whose content is prescribed by the securities regulators' National Instrument 51-102; and,

b. the Annual Information Form and Statement of Executive Compensation, whose content is prescribed by securities regulators' National Instrument NI 51-102.

c. OPG shall respond to any comments or requests for further information on the financial statements, made by the Minister, Deputy Minister or Ministry staff in a timely manner.

5.6 OPG shall provide quarterly briefings to senior officials of the Ministry on OPG's operational and financial performance against plan.

5.7 OPG shall provide reports and information to the Minister and Ministry of Finance, as required, from time to time, as per subsection 53.4 (4) of the EA. Reports and information requests from the Ministry of Finance shall be made through the Minister.

5.8 The OPG Board Chair shall report to the Minister annually on the effectiveness of this MOA. Such report shall be provided to the Minister in writing within 90 days after the end of each fiscal period.

5.9 OPG shall provide to the Ministry quarterly status update on the progress of the Darlington Refurbishment Project.

5.10 OPG will notify the Minister in advance of any new debt issuances or changes to existing debt arrangements.

6 PERFORMANCE EXPECTATIONS

6.1 Operational Expectations

6.1.1 OPG shall operate its electricity and generating assets safely, efficiently and cost-effectively, and in accordance with all applicable safety and environmental regulations and standards.

6.1.2 OPG shall pursue cost-effective and efficient operational improvements that maintain the reliability of operations, the safety and security of OPG assets, employees and the public. This includes integrating considerations for projected impacts of climate change into operations and planning.

6.1.3 OPG shall undertake periodic benchmarking appropriate for its operations and type of assets, including as part of its submissions to the Ontario Energy Board.

6.1.4 OPG shall operate its Ontario based portfolio of electricity and generation assets in a manner that contributes to Ontario’s and Canada’s environmental objectives.

6.1.5 OPG shall ensure that a system is in place for the creation, collection, maintenance, and disposal of records in accordance with corporate policy, guidelines and best practices.

6.1.6 OPG shall make information targeted to the general public available in French where it meets a need to do so.

a. Recognizing that OPG's direct interaction with the public is often limited to regional or host community communications or broader public safety, OPG shall make information available in French only if reasonable in the circumstances.

b. For greater clarity, OPG shall provide the following services and products in French: advertising, news releases and educational materials where it meets a need to do so. As well, public safety communications, annual financial reports and educational materials will be provided in French and French speaking spokespeople will be made available as required for public and media interaction. French language products will be listed under a specific heading on the OPG web site.

c. This list shall be reviewed by OPG annually.

6.1.7 OPG shall support pursuing energy efficiency improvements in its operations where economic.

6.1.8 OPG shall also continue to report on its energy efficiency results in its annual Sustainability Report.

6.2 Financial Expectations

6.2.1 As an OBCA Corporation and reporting issuer with a commercial mandate, OPG shall operate on a financially sustainable basis, earning a commercial rate of return in order to be able to service its current and future liabilities, to support the appropriate level of capital spending and to maintain or increase the value of its assets for its Shareholder.

6.2.2 OPG shall finance project investments and its operations in a prudent and cost-effective manner.

6.3 Compensation

6.3.1 OPG shall annually inform the Shareholder about its compliance with applicable legislation and regulations governing employee compensation.

6.3.2 Subject to paragraph 6.3.3, as set out in section 137 of the OBCA, the board of directors may fix the remuneration of the directors, officers and employees of the corporation.

6.3.3 Any changes to OPG's executive compensation program must comply with applicable legislation and regulations governing executive compensation.

6.3.4 OPG shall notify the Shareholder of any plans to change director remuneration policies prior to finalizing said policies.

7 LABOUR NEGOTIATIONS

7.1 In advance of commencing discussions for the renewal of its collective agreements with its unions, OPG shall seek advice from the Ministry on Provincial policy direction and relevant fiscal considerations affecting labour negotiations in the broader public and/or energy sectors.

7.2 OPG shall present any bargaining mandates to the Ministry. The Ministry will advise OPG on process for obtaining Treasury Board approval, as applicable.

7.3 When a collective agreement has been negotiated, OPG shall inform the Ministry of the results and details of the collective agreement prior to ratification. The Ministry will advise OPG on process for obtaining Treasury Board approval, as applicable.

7.4 When a collective agreement has been ratified, OPG shall inform the Ministry of the results and details in a timely manner.

8 COMMUNICATIONS

8.1 The OPG Board of Directors and the Minister shall meet as needed to enhance mutual understanding of interrelated strategic matters.

8.2 OPG's Board Chair, OPG's President and Chief Executive Officer and the Minister shall meet on an as needed basis.

8.3 OPG's President and Chief Executive Officer and the Deputy Minister shall meet on a regular and as needed basis on matters of mutual importance.

8.4 OPG's senior management and Ministry senior officials shall meet on a regular and as needed basis to discuss new and ongoing issues, discuss strategic business objectives and OPG's performance, and to clarify expectations or to address emergent issues.

8.5 The Shareholder shall specifically seek OPG's input on policies that may impact OPG, when and as appropriate.

8.6 OPG shall consult with the Ministry, as appropriate, on key communication issues that may affect the Ministry or OPG. OPG shall keep the Ministry informed, as appropriate, of the key communication issues in a timely manner, and in advance if it is possible or appropriate to do so, having regard to the seriousness of the key communication issue.

8.7 OPG shall periodically share with the Ministry, a plan that outlines the company's scheduled marketing and communications efforts.

8.8 In all other respects, OPG shall communicate with government ministries and agencies in a manner typical for an Ontario Corporation of its size and scope to ensure a timely flow of information. OPG shall keep the Ministry informed, as appropriate, of the its communications with other government ministries in a timely manner.

9 TERM OF THIS AGREEMENT

9.1 The terms of this MOA may be added to, deleted, varied or amended from time to time, only with the written consent of both parties.

9.2 Subject to paragraph 9.2.1 of this MOA, this MOA shall be in effect for five years from the date of execution by the Minister, and the Shareholder and the OPG Board Chair shall endeavour to renew or revise this MOA by the expiry date, or earlier, as required.

9.2.1 Despite section 9.2 of this MOA, the provisions of this MOA, as may be amended from time to time, shall continue to be in effect until the renewed or revised MOA is executed by both parties.

9.3 The Shareholder and the OPG Board Chair shall reaffirm this MOA for continuance with a change in either the Minister or Chair, and such reaffirmation may be done by letter and such letter shall be considered part and parcel of this Agreement as if the party or parties reaffirming the MOA had duly signed and executed an amendment to the MOA.

9.4 This MOA shall be posted publicly on OPG's website.

SIGNATURES



Wendy Kei
Board Chair
Ontario Power Generation, Inc.

August 27, 2021
Date



Honourable Todd Smith
Minister of Energy

September 3, 2021
Date

APPENDIX 1: STATUTES OF PARTICULAR APPLICATION

Accessibility for Ontarians with Disabilities Act, 2005
Auditor General Act
Broader Public Sector Accountability Act, 2010
Broader Public Sector Executive Compensation Act, 2014
Business Corporations Act
Electricity Act, 1998
Freedom of Information and Protection of Privacy Act
Ontario Energy Board Act, 1998
Public Sector Compensation Restraint to Protect Public Services Act, 2010
Public Sector Expenses Review Act, 2009
Public Sector Salary Disclosure Act, 1996
Public Sector and MPP Accountability and Transparency Act, 2014

APPENDIX 2: APPLICABLE TB/MBC/MOF DIRECTIVES

Compensation Arrangements Compliance Report Directive
Perquisites Directive
Procurement Directive
Travel, Meal and Hospitality Expenses Directive
Ministers' Staff Commercial Transactions Directive
Broader Public Sector Executive Compensation Program Directive
Broader Public Sector Compensation Information Directive

Note: Amended, revised or successive versions of the directives listed above continue to apply to OPG. Where a directive applies, all associated policies, procedures and guidelines also apply.

Letter / Statement of Affirmation
Pertaining to the Memorandum of Agreement, Effective September 3, 2021, Between His Majesty the King in right of Ontario, as represented by the Minister of Energy and Mines (formerly known as Her Majesty the Queen in right of Ontario, as represented by the Minister of Energy) ("Shareholder") and Ontario Power Generation Inc. ("OPG")

WHEREAS the Shareholder and OPG entered into a memorandum of agreement effective September 3, 2021 ("MOA"), which established the accountability relationship between the Shareholder and OPG;

AND WHEREAS section 9.3 of the MOA requires that the Minister of Energy and Mines and the OPG Board Chair shall reaffirm this MOA for continuance with a change in either the Minister of Energy and Mines or OPG Board Chair and that such reaffirmation may be done by letter;

AND WHEREAS Stephen Lecce was appointed as Minister of Energy and Mines on March 19, 2025;

NOW THEREFORE, in accordance with the above-noted requirement, we, the undersigned, affirm that the attached MOA continues to remain in force and effect.



Stephen Lecce
Minister of Energy and Mines

September 22, 2025
Date



Wendy Kei
Board Chair
Ontario Power Generation Inc.

March 27, 2025
Date

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
20-06 CIO Insider Threat Data Loss Prevention (ARC 2020 Q4)	[redacted]	[redacted]	[redacted]

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		[redacted]	

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
20-19 Renewable Generation and Power Marketing ("RGPM") Asset Management & Maintenance Follow-up (ARC 2020 Q4)	Generally Effective (White)	A significant number of maintenance Work Order Tasks (“WOTs”) remained backlogged, including Priority 1 (“P1”) WOTs.	Management will: 1. Revisit the priority definitions for WOTs including the following; • For P1 WOTs, provide clarity for consistent and accurate assignment in this category; and • In the event that a P1 WOT requires planning for a permanent or longer term solution, encourage workers to document the findings of that assessment in AS7, with consideration given to the appropriateness of the classification of the WOT and revise accordingly, with updated completion dates being established; 2. Clarify the timeframe for completing WOTs, for each priority level, and management’s expectations around WOT backlog (e.g. what level of backlog is considered acceptable). Update RG-PROC-MA-0002 to include the clarification as appropriate; 3. Establish an aging report to identify and prioritise the review of backlogged P1 tasks to confirm the priority rating was assigned accurately and follow-up on the reasons for the backlogs; and 4. Re-emphasise the definitions of the priority codes so that there is consistent classification and completion of work order tasks by all stations. **Status: Closed**
		Equipment criticality codes were not yet included in AS7 for some equipment records.	RPGM Management will reinforce with workers the expectations that criticality codes are to be assigned to all equipment, identify the equipment with missing criticality information, and track criticality code assignment to completion. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
20-21 Nuclear Asset Management-Equipment Reliability & Maintenance (ARC 2020 Q4)	Effective (Green)	Assigned Work Order ("WO") priorities in AS7 are not reflective of the level of effort required for action.	Darlington and Pickering Nuclear Station's Management will perform a self-assessment on the outstanding WO Backlog in AS7, which was priority coded through N-PROC-MA-0008, and ensure they are appropriately priority coded. (AR 28238508 for DNGS and AR 28238518 for PNGS). **Status: Closed**
		Action plans in health reports are not always updated in System IQ.	Darlington and Pickering Nuclear Station's management will share audit findings with the Performance Engineering and Component Engineering departments as part of the pre-job brief for the Q4-2020 SHR and PHRs that are to be prepared in January 2021. Department Manager will review a random sample of Q4-2020 and Q1-2021 SHRs and PHRs to confirm information is updated. This random sample review will be added as an agenda item for the Engineering Review Board meetings for both the DNGS and PNGS Stations over Q1-2021 and Q2-2021 to ensure that the information contained in SHRs and PHRs are updated. **Status: Closed**
20-25 Pickering Safestore Program Audit (ARC 2020 Q4)	Generally Effective (White)	Overarching risk-based project strategies and controls were not sufficiently defined for the Pickering Safestore program.	Develop and roll out to the Safe Storage organization the Project Controls Plan. The plan will define the expectations or requirements for the program and projects within the program where they differ from those of the standard project governance. **Status: Closed**
			Update the Safe Storage Program PMP to align with the project controls plan and current governance, program plans and strategies. **Status: Closed**
		The Safe Storage program progressed through project phasegates without completion of some pre-requisite deliverables.	Perform an execution readiness PDRI. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
			Update the Safe Storage phase gating Pickering Safestore Review board (“PSSRB”) presentation template to include a listing of any outstanding deliverables, target completion dates and associated justification and risk for non-completion. **Status: Closed**
20-27 Darlington Nuclear Refurbishment ("DNR") Quality Oversight (ARC 2020 Q4)	Generally Effective (White)	There is a lack of evidence to demonstrate that vendors are sufficiently closing corrective actions.	1. Track to completion a selected number of high severity observations documented in the Master Observation Repository (MOR) with vendor corrective actions. The purpose of the review is to determine whether the vendor took the appropriate course of action in closing out their corrective action; and 2. Update the Darlington Refurbishment Program Quality Surveillance Guide (NK38-GUID-09701-10038) to document this requirement. **Status: Closed**
		Document change control in SAWPLO oversight planning was not implemented.	1. Review the Annual Plan on a regular basis to ensure alignment with the P6 schedule (particularly the Window Start and Finish dates) and issue new revisions on an as needed basis to document changes to the plan; 2. Ensure that updates to Window Plans are revision controlled; and 3. Update the Darlington Refurbishment Program Quality Surveillance Guide (NK38-GUID-09701-10038) to document this requirement. **Status: Closed**
		There is a lack of documentation to validate that the planning and reporting of some field surveillance activities were consistently executed.	Management has already taken action to implement a new oversight checklist that addresses the gaps found during the audit. The new oversight checklist includes specific sections for oversight to be performed, surveillance details, and adjustment to the checklist to reflect that the document was sent to PM to address the gaps found in Unit 2. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Some Quality Oversight staff did not complete training linked to their role qualifications.	1. QM management will ensure that staff linked to supplementary qualification complete the qualification; and delink employees who are not required to complete qualification. 2. The Balance of Plant Management has linked all individuals to the required training qualifications with the intent to complete as noted above. **Status: Closed**
20-28 DNR U2 Cost Allocation (ARC 2020 Q4)	Generally Effective (White)	Expenditures incurred in connection with the Unit 2 refurbishment, equal to the amount of the credit note issued by CanAtom, were reflected as advance payments for future refurbishment activities on subsequent units.	1. On an ongoing basis, cost forecasts will continue to include all contract related elements that are paid or recovered from CanAtom under the Re-tube & Feeder Replacement (“RFR”) contract. Management will also provide visibility on the impact of the commercial settlement within DNR reporting to the Darlington Refurbishment Committee (“DRC”), including amounts earned back and impacts on the overall cost forecasts and contingencies. **Status: Closed**
			2. Potential outcomes under the final Commercial Settlement will be reviewed with the DRC at the March 2021 Darlington Refurbishment Program Management Meeting. **Status: Closed**
		Inconsistent level of detail of some Estimate at Completion (“EAC”) variance explanations in quarterly Darlington Nuclear Refurbishment (“DNR”) reports.	Management will ensure that a consistent approach is taken to provide relevant period-over-period variance explanations for forecast changes to ensure the DRC has an understanding of the drivers related to the change. **Status: Closed**
		Contingency for Unit 2 was not drawn in a manner consistent with the timing of associated costs being incurred.	As part of the project close out process for Unit 2, management will undertake a reconciliation of remaining contingency and ensure any distribution to appropriate cost accounts is completed as appropriate. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
			As part of the controls framework established for subsequent units, management has augmented the monthly risk review process to include a quantitative risk assessment to enhance reporting of risks, available contingencies and forecasts. **Status: Closed**
			Contingency usage and risks are currently in place for DRC and management reporting. Management will ensure that the consistent reporting of contingency and risks continues. **Status: Closed**
21-01 2020 Business Expenses for Board of Directors (ARC 2021 Q1)	Effective (Green)	N/A: No Findings	N/A: No Findings
21-02 Treasury Financing & Operations (ARC 2021 Q2)	Effective (Green)	Periodic reviews of user access to the banking systems supporting bank accounts were not consistently performed.	Treasury will: 1. Remind all user groups of the need to advise Treasury of any changes in bank-system access requirements on a timely basis, with periodic reminders being provided; and 2. Implement a process to review user access to all banking systems on an annual basis at minimum, and confirm with non-Treasury user groups the continued need for access for users within their groups as part of that review process. **Status: Closed**
		A listing of pension cheques which have been issued but not yet cashed is not maintained, and the value of stale-dated cheques unknown.	1. Treasury will identify a Banking Operator for the Pensions account. **Status: Closed**
			2. Pension & Benefits group will collaborate with Pay Services to reconcile the balance in the Scotiabank A/c # 47696-02971-19, including itemizing a listing of cheques outstanding at the time of the reconciliation. Going forward, management will prepare and review a reconciliation of the account on a monthly basis. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
21-03 Business Case Summary (ARC 2021 Q4)	Requires Improvement (Yellow)	Review and performance activities within BCSs were inconsistently executed.	1. A combined Gate Progression Form/Business Case Summary module is currently being tested within ePMX This module will ensure the following: • Life-to-date (“LTD”) amounts are aligned to financial systems; • Automated workflow to link to and notify Finance to release funding, once the BCS is approved (and exploring feasibility of linking directly to funding release in a future module); and • Automated workflow to ensure the preparation and record-keeping of the Gate Progression Form, prior to BCS approval. Additional enhancements to the Digital BCS is planned to include the following: • Constraint to verify OAR Element against the approved Business Plan; • Constraints to ensure Costing tables totals are aligned; and • The requirement to include the basis of estimate to support the BCS. In addition, we will explore feasibility of using ePMX to address the in-budget vs. out-of-budget observation in a future module. **Status: Closed**
			2. Investment Management to provide a guidance roll-out for BCS Stakeholders/approvers to reinforce expectations on the following: • Finance’s role in approving BCSs and guidance on best practices in reviewing; • OAR Signatory and Element identification; • Executive Authority Approval identification; and • Gate Progression Form requirements. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		The Post Implementation Review ("PIR") Procedure had not been reviewed since 2010, and its requirements were not consistently applied.	The procedure will be reviewed and updated with an enhanced process. The roll out of the new procedure will include communication with key stakeholders regarding expectations. **Status: Closed**
		BCS guidance documents and rates used for project assessment were not periodically updated.	Management plans to formalize the review process and update the BCS Toolkit to remove any perceived inconsistencies. **Status: Closed**
21-04 Network Security, Threat & Vulnerability Management (ARC 2021 Q3)	[redacted]	[redacted]	[redacted]

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		[redacted]	[redacted]
21-05 Bruce Power Ring Fence (ARC 2021 Q1)	Generally Effective (White)	Two individuals were not removed from the Ring Fence Staff List after joining the Energy Markets team.	Energy Markets management will implement an onboarding check to ensure that individuals joining the EM team from other OPG groups are not on the BPRF staff list, and that the individual no longer has access to BPRF information. **Status: Closed**
		System access reviews were not performed for Curator and Documentum for 2019.	All electronic ring-fenced information is now centralized to a single electronic storage location (i.e. Documentum). Quarterly reviews resumed in Q3 2020, and continue to be performed by CIO. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
21-06 Asset Suite Upgrade Project (ARC 2021 Q4)	Effective (Green)	The Project Management Plan was not fully completed, reviewed and approved prior to Execution.	CIO IT Projects management will submit a Document Change Request to update IT Project Management governance with the requirement that unclear or evolving elements in project artifacts are clearly identified as such, when submitted for review and approval. **Status: Closed**
21-08 Shared Services Re-Imagine 2.0 (ARC 2021 Q4)	Generally Effective (White)	Target measures in the Post Implementation Review plan were not directly aligned with the potential project benefits.	Management will assess whether the savings identified in the value tracker will result in sustained productivity improvement, and document the assessment in the PIR. **Status: Closed**
		Scope definition and detailed design were not completed for two initiatives even while the Re-Imagine 2.0 project was well into execution.	Management will: 1. Complete the planning phase deliverables for the two initiatives. If it is determined that Assess Finance will not be delivered as part of Re-Imagine 2.0, a change control form will be prepared. 2. Work with the CIO Project Management organization to update the IT Project Management Guideline (OPG-MAN-08120-0002) to incorporate control expectations around the use of Agile PM methodology. **Status: Closed**
21-12 Environmental Management System ("EMS") Internal Audit Program (ARC 2021 Q2)	Effective (Green)	N/A: No Findings	N/A: No Findings
21-13 Relocation Expenses and Property Management (ARC 2021 Q2)	Generally Effective (White)	Procedural governance and relocation brochures are outdated and require review.	Real Estate Management will: 1. Register OPG-STD-0120 in the GOD, and assign owners and reviewers responsible for the Standard; 2. Work with Labor Relations to determine the appropriate course for the relocation brochures for represented staff, and implement the changes as appropriate; and 3. Update ERS internal procedures / forms, and the Real Estate intranet site. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Purchase guarantee home values were not determined in a consistent manner.	Real Estate Management will define procedures on how PG values will be determined, and apply the procedure when offering PG values to employees. **Status: Closed**
		Automation opportunities exist in the employee relocation process to reduce manual effort.	Real Estate Management will work with SSO to discuss the possibility for SSO to own the employee relocation program starting year 2022. Once the future ownership of the relocation program is determined, the relocation team will review the required work with Shared Services to identify and implement appropriate and additional monitoring opportunities. **Status: Closed**
21-14 Fleet Management (ARC 2021 Q2)	Requires Improvement (Yellow)	Business Unit (“BU”) Managers did not always fulfill their responsibilities to secure, maintain and monitor usage of fleet assets.	Supply Chain will work with Human Resources to implement a CBT course around the Fleet Management Procedure (OPG-PROC-0162) in MyPower Learning, and require BU Managers and fleet asset owners to complete the training annually. In addition, Management will also review the Fleet Management Procedure to identify opportunities to reduce administrative burden for both Supply Chain and BU Managers. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Lease-versus-buy analysis was not performed as required, and some fleet assets were not acquired through the Fleet Management group.	Supply Chain Management will ensure that: 1. Fleet Management governance is updated to clarify the expectation to prepare lease-versus-buy analysis. In particular, the analysis is required for certain types of assets (e.g. non-standard assets), but not others such as passenger vehicles; 2. FMS and Procurement Specialists require BU Managers to produce the lease-versus-buy analysis for applicable assets (e.g. non-standard assets), before the asset can be leased or purchased; and 3. Guidance to BU Managers will be reinforced, annually through the Fleet Management CBT, on the expectation to prepare lease-versus-buy analysis for non-standard assets, and the need to inform FMS when assets were purchased through the Procurement Specialists so that fleet inventory can be updated. **Status: Closed**
		BU Managers were not informed when employees used the OPG Motor Pool (Enterprise CarShare).	1. Subsequent to the audit fieldwork, Supply Chain Management worked with Enterprise CarShare to require users to acknowledge, in the CarShare program website, the terms of the program (e.g. non-business usage of vehicles is not allowed) before users can make vehicle rentals. **Status: Closed**
			2. Supply Chain Management will also work with Enterprise CarShare to develop a process to inform employees' supervisors whenever a motor pool vehicle is used. This could be through automation where emails are sent to the employee's supervisor when a motor pool vehicle is checked-out and returned. If automation is not practical, FMS will investigate other avenues to ensure employees' supervisors are informed of the motor pool usage, which could include charging the usage costs directly to the employee's credit card, and/or forward the Enterprise monthly consolidated invoices to the employees' supervisors for information. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Fleet assets' utilization was not monitored and some assets were underutilized.	FMS will publish metrics, by business unit, identifying under utilized assets and share these metrics with the Controllership and Business Unit Leaders annually to facilitate their oversight. **Status: Closed**
		Some employees used premium fuel for fleet assets although not required, resulting in higher costs to OPG.	FMS will update OPG-PROC-0162 to clarify that regular unleaded should be used for fleet assets. In addition, metrics will be published to identify premium fuel usage, and FMS will share these metrics with the Controllership and Business Unit Leaders every six months to facilitate their oversight. **Status: Closed**
21-15 Consulting Services Procurement (ARC 2021 Q3)	Generally Effective (White)	The potential value of one work assignment communicated to proponents was significantly different from the eventual purchase order ("PO") issued.	Management will: 1. Revise governance to include guidance to be considered when establishing an "opportunity value" when advertising RFPs in Ariba Discovery; 2. Assess the feasibility of adopting automation to link AS7 PO value to the advertised opportunity value in Ariba Discovery; and 3. Define processes for Purchasing Agents to follow in situations where the "opportunity value" advertised for an RFP differs significantly from the PO value. **Status: Closed**
		One instance was noted where consulting services of $60,000 was not competitive sourced, and Single Source Justification was not prepared.	Management will: • Reinforce with BU Requisitioners and require them to conduct secondary stage competition before consulting services work is assigned to Masters Agreement or Vendor of Record suppliers; and • Work with BU Requisitioners to complete the OPG-FORM-0003 retroactively for the PO where required. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Evaluation documents of vendors' proposal were not consistently signed-off by Supply Chain and the requisitioner.	Management will continue with the annual self-assessments on Purchasing Agents' compliance with OPG-PROC-0058, and share observations from the assessment with the Purchasing Agents and Senior Managers to continuously improve. In addition, management will explore the possibility of including a system workflow that will ensure that a signed evaluation matrix is on file before POs are issued. **Status: Closed**
21-17 Water Management and Dam Safety Audit (ARC 2021 Q1)	Generally Effective (White)	There was no established centralized tracking process to ensure actions have been taken to address dam safety review recommendations.	A standardized process is being developed for RGPM to track, monitor, and assign action items, including DSR recommendations. To improve the tracking, a unique identifier will be assigned to DSR recommendations, that can be used to track the work assigned in AS7 modules. DSR recommendations recorded in the DataCube system will include the unique identifier and status (e.g. not started, on-going or completed) including assignment and a planned completion date. Management will consider whether opportunities for automated tracking of DSR recommendations to source systems is feasible, and determine whether the benefits of such automation would outweigh any incremental set-up costs, bearing in mind the RGPM systems road map for future developments and the timeline for such benefits to arise (e.g. the potential move from AS7 to AS9). **Status: Closed**
		Regulator's agreement to the deferral of due dates for Annual Compliance Reports and Implementation Reports were not always documented, and the reports were not prepared in a consistent format.	A review of the Annual Compliance Reports will be performed to identify opportunities to improve consistency among the Operations groups with the documentation that is provided and establishing a common format. Management will reinforce the need for written confirmation of agreed to deferrals of submission dates and other similar agreements that may be verbally conveyed by the MNRF. In some cases this may be in the form of an email from OPG to the MNRF memorializing the conversation. **Status: Closed**

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Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
21-18 Darlington Outage Management (ARC 2021 Q4)	Generally Effective (White)	There are discrepancies with Key Performance Indicators ("KPIs") being reported from different sources.	Management will perform a Self-Assessment to review in-house outage preparation and execution metrics and confirm their suitability for continued use for future outage project monitoring. Custom Designed and In-house outage preparation and execution metrics are used by Darlington site to provide metric drill down capability and a user-friendly Graphical User Interface ("GUI"). The metric also offers capability to identify discrepancies with CASSI reporting metrics and initiate data issue identification and resolution. **Status: Closed**
		Industry and OPG outage scope completion targets were not achieved and there is a scope variance on the current outage in progress.	Scope Variance Improvement initiatives to address this gap have been captured under 2021 GDAR KPIs managed by Fleet Work Management such as: 1. Review all existing Work Requests (WRs) and Work Orders (WOs) prior to the Scope Freeze Date to establish the approved scope for the Planned Outage to prevent later scope injections which would result in a reduction to Scope Variance for that Planned Outage. 2. Outage Managers to follow newly revised MA-13 R19 updated in the fall of 2020 to include more exception codes to be used for Work Orders that are removed from Outage Scope for being either duplicate WOs or Cancel as not required. 3. Outage managers will identify WOs that are injected after SF due to Senior Management Decisions. This will allow an assessment of the impact of these on scope variance. 4. Fleet Outage (CFAM) to conduct discussions and benchmarking on the Planned Outage Scope Variance KPI metric with the COG Group including Outage Managers from both Bruce Power and New Brunswick Power. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
			Scope Completion Action: Establish optimized Scope threshold for D2421 to support successful scope completion considering available resource profile forecast. **Status: Closed**
		There is no documented interface for assigning deferred Work Orders from the Station to Refurbishment business unit.	A strategy Memorandum of Understanding will be prepared between the Darlington Operations and DNR organizations, describing the process for transferring deferred WOs. This work will be considered for potential scope for refurbishment outages, and consideration will also be given as to whether the benefits of an automated solution between OMS and ROOMS would outweigh the costs of development and implementation. **Status: Closed**
		Planned Budgeted Focused Outage KPIs are not included in the Functional Area reports.	Management will update FAS to include Planned Budgeted Focused Outage Tier 1 metrics which include Safety / Schedule / Cost / Quality. **Status: Closed**
21-19 CANDU Owners Group Audit (ARC 2021 Q1)	Generally Effective (White)	The OPG R&D Advisory committee may not be achieving all of its defined objectives.	1. Management has developed and issued an annual survey to gather input from applicable Darlington and Pickering facility leaders on station needs for OPG's R&D focus areas over the next three to five years. This information was shared with TCRs in the Q1 2021 R&D Advisory meeting for their consideration into the 2021-2022 COG R&D Program. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
			2.3 Management will clearly define a framework for value assessment and tracking through N-PROC-MA-0092 and associated guides by defining roles and accountabilities of the TCRs, Program Owner and R&D Advisory Committee members. Specific focus areas include tracking project deliverables, project implementation at applicable site(s) and benefit/value assessments. **Status: Closed**
		Some Technical Committee Representatives (TCRs) did not complete their responsibilities for developing the annual COG R&D Program.	In alignment with the revision and roll-out of N-PROC-MP-0092 (see management actions in Finding 1), management will define clear roles and accountabilities for site SPOCs, TCRs and the Program Owner in order to improve R&D project and deliverable tracking, by conducting a monthly review of the TCRs performance as it relates to the review of reports and disposition of comments to identify trends in late commitments and resolve issues as required. **Status: Closed**
		An OPG framework to manage and oversee all COG-related activities requires revision and fleet-wide rollout.	Management will revise N-PROC-MP-0092 in order to define the process for the management and oversight of strategic R&D programs, roles and responsibilities of JP Owners (both R&D and non-R&D) and Line Management, and roles and accountabilities of the Program Owner for JPs in respect of performance. **Status: Closed**
		There was no consistent process to assess whether joint projects being proposed by COG or being pursued by OPG were already a part of the COG membership benefits.	Management will implement a checklist for JP proposals which will detail member benefits and confirm that new JPs are not covered within the bounds of the membership fee. JPs owners will be required to complete the checklist prior to obtaining COG SPOC approval. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
21-21 Right Work, Right Time, Right Value ("RWRTRV") - Station Productivity Initiative (ARC 2021 Q3)	Requires Improvement (Yellow)	Key Performance Indicator (“KPI”) reduction targets outlined in the Right Work, Right Time, Right Value (“RWRTRV”) Charter were aspirational, and no progressive criteria was established to assess results.	Management will continue to work with site Maintenance managers to further review, develop, and document initiatives which will continue to improve/sustain Maintenance Efficiencies. Part of this review will include the determination of future Maintenance measures and targets. Any revised measure and targets will be included in the 2022 Power BI reporting platform. **Status: Closed**
		Formal close-out of completed sub-initiatives was not performed and documented.	CFAM Management will prepare a close-out report of the completed initiatives and sub-initiatives before year-end. The report will evaluate if the RWRTRV met the objectives; initiatives have been completed and tasks that can be reviewed further; and what went well and opportunities to improve. The report will be presented at a senior leadership meeting (e.g. Site Excellence Meeting). **Status: Closed**
		Some KPIs outlined in the Charter were not consistently reported to the Nuclear Executive Committee (“NEC”) as the overall initiative progressed.	Management will, as part of the close-out report, include a summary of the current achievements and progress against the KPI’s and where deemed appropriate, document the rationale for dropping KPIs from the original Charter, and report the results to Senior Leadership and other applicable stakeholders. **Status: Closed**
		Initiative-wide risks documented in the Charter were not formally tracked and dispositioned within the initiative risk register.	Management will include the risks from the Charter for the RWRTRV initiative and monitor and respond to these risks if they impact the objectives of the successful completion of this project. The requirement to capture Charter risks in a risk log and where they should be recorded (e.g. ePMX or Sharepoint) will be included in governance and/or guides for future projects. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
21-23 Retube and Feeder Replacement Project – Darlington Nuclear Refurbishment ("DNR") Unit 3 (ARC 2021 Q2)	Effective (Green)	Risks associated with the adoption of the One Team Approach were not formally tracked within the risk register.	Management will formally document the risk associated with the One Team Approach in ePMX with RFR CanAtom. The risk will be periodically monitored to ensure that proactive and preventative actions are taken in response to emerging circumstances. **Status: Closed**
		Tooling Management Plan governance does not include formal guidelines for multiple series during overlap.	RFR Project Management will work with CanAtom to update the RFR Tool Management Plan (and associated plans as required) to include guidance on multiple series during overlaps, including reassessment of tooling quantities and deployment schedules. **Status: Closed**
21-24 Unit 1 & 4 Planning & Readiness Review (ARC 2021 Q3)	Effective (Green)	Different Quantitative Risk Assessment ("QRA") confidence levels were achieved when compared to Unit 2 and Unit 3 working schedules for their execution estimate releases.	The duration of the working schedule (P20/P17 for U1/U4, respectively), medium confidence duration for U1 (P50), and the high confidence schedule (P90) have been provided in the U1EE memorandum to the Board of Directors. **Status: Closed**
			Management will continue to capture lessons learned after each major work window and segment, including those executed on the refurbishment of U3. Management will evaluate these lessons learned and incorporate adjustments in U1's forecast schedule and, depending on timing, U4's baseline schedule that will be published at U4EE. **Status: Closed**
		General Electric has not yet issued their Revision A and 0 schedules for the engineering contract related to Turbine Generator ("TG") modification works, resulting in potential schedule risks related to engineering deliverables and execution phase durations.	Upon receipt of the Level 2 and 3 GE schedules, management will evaluate their impact on the overall schedule and, if necessary, implement mitigation plans to avoid any impact on the overall durations. Management will report on status of this on an ongoing basis. **Status: Closed**

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Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
21-25 DNR Tools and Consumables (ARC 2021 Q1)	Generally Effective (White)	Inadequate control over tools that are issued and remained active past their calibration, and/or inspection date.	1. Fleet Maintenance Programs will work with Human Resources & CMO to acquire the correct vendor information by employee number (worker employer name, hire/rehire dates, termination date, and supervisor contacts) required to enhance the TCS Overdue Tool Notice auto email process. Fleet Maintenance will also work with the CMO groups to identify the correct level of OPG CMO contact to receive these notifications going forward to continuously monitor and manage contractor progress to ensure improved performance. **Status: Closed**
			2. CMO Management will establish a process to following up with vendor leadership when overdue tools are more than 14 days past due. **Status: Closed**
			3. Management created DCR # 0000156616 against N-PROC-MA-0015 R002 Tool Control, to remove statement (a) from Section 1.4.1.1 of the procedure which states that “Unless otherwise approved by CMO, contractors requiring tools shall have stores tools issued through a CMO representative only.” This procedure is misaligned with the current process and objective of the ITC where efficiency gains are produced by enabling the withdrawal of tools directly by vendor workers. **Status: Closed**
		Dispensed and unreturned coveralls were not tracked and dispositioned where appropriate.	1. Management will utilize the Unitech/ OPG Inventory process to reconcile the number of coveralls. Monthly counts with “on-hand” trending. **Status: Closed**
			2. & 3: Management is pursuing acquiring coverall dispensing machines to ease the administrative burden and have better traceability on coverall usage. (Refer to Risk 1298 in the EBx database). **Status: Closed**

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Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
			4. Management is pursuing acquiring coverall dispensing machines, therefore the contract with Crossby Dewar will not be renewed after it expires in July 2021. **Status: Closed**
21-26 Darlington Nuclear Refurbishment ("DNR") Program Initiatives (ARC 2021 Q4)	Generally Effective (White)	Benefits associated with the Strategic Improvement Initiatives were not consistently measured and reported.	Management will complete a report on the Strategic Improvement Initiatives with the aim of assessing the extent of benefit realization. **Status: Closed**
		Information in management reporting for Functional Initiatives was not always accurate and consistent.	Management will establish an expectation for identifying KPIs which will be used to track the progress of the initiatives. KPIs will be SMART and linked to measurable criteria. **Status: Closed**
21-27 Advanced Inspection & Maintenance ("AIM") Project Management & Execution (ARC 2021 Q4)	Effective (Green)	N/A: No Findings	N/A: No Findings
21-31 Shared Services Re-Imagine 1.0 (ARC 2021 Q4)	Not Effective (Red)	Some of the Re-Imagine 1.0 workstreams have either not fully met Line of Business requirements, and/or have not been adopted in business processes.	1. For workstreams where delivered solutions did not entirely meet the BRD requirements, Management will engage the business groups to perform a LL exercise. As part of the LL, Management will: • Review the solutions that Re-Imagine 1.0 delivered (e.g. whether they continue to meet business needs); • Identify the high-level requirements that were not addressed through the project and determine whether they are still needed by the business units, and • Assess whether additional work is required to resolve the requirements that were not addressed by Re-Imagine 1.0, so they could be considered for future base-support and/or inclusion in the project portfolio for prioritization. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
			2. For the Finance Legal Consolidation workstream, Management is in the process of getting BPC Consolidation operational by entering historical financial results into the system, and resolving differences between the system output and the official results manually prepared. Management will define a plan to adopt BPC Consolidation, including defined milestones for the following activities: • Entering 2021 financial results into BPC consolidation; • Performing parallel run for several quarters (with BPC consolidation and manual consolidation being performed concurrently); • Resolving differences from the parallel run; and • Go-live. **Status: Closed**
		Some Robotic Process Automations developed by the Re-Imagine 1.0 project are no longer in use, while others required enhancements after going into production.	1. For new AI and RPA tools are deployed into production, checklists and documentation will be provided to business unit management to inform them of the steady-state support requirements for the tools (e.g. tools need to be continually updated to incorporate new scenarios, CIO support contacts). **Status: Closed**
			2. IT Services will ensure that ongoing support is available to enable business units to sustain the tools and troubleshoot unforeseen issues. **Status: Closed**
		The Post Implementation Review (“PIR”) was finalized late, and a change control form was not completed to update the PIR requirement.	The PIR procedure will be reviewed and updated with an enhanced process. The roll out of the new procedure will include communication with key stakeholders regarding expectations. **Status: Closed**

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Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
22-02 Disaster Recovery Plan (ARC 2022 Q2)	Generally Effective (White)	Issues impacting recovery time identified during the exercise were not fully investigated.	For all issues encountered during the 2023 Disaster Recovery exercise, CIO management will fully investigate root causes to understand all failures that resulted in the adverse condition and document those failures in the final report. **Status: Closed**
		Exercise recovery time targets were longer than the maximum tolerable downtime for some applications.	Enterprise Emergency Management (“EEM”) will: 1. Identify discrepancies by comparing applications listed in Vital Systems, section 3.3, of BIAs against available DRPs and identify applications with no DR plan; and 2. Based on comparison between BIAs and DR plans, coordinate where necessary with respective Business Units Business Continuity SPOCs and CIO to ensure BIAs accurately reflect the business maximum tolerable downtime. **Status: Closed**
22-03 Software Management (ARC 2022 Q1)	Requires Improvement (Yellow)	Extensive information about software versions installed on OPG machines was shared with a third party outside Canada.	CIO Cyber Security management has obtained written confirmation from the third party confirming that data relating to software installs on OPG machines has been purged, and that the information was not involved in any data breaches or data leakage events to their knowledge. **Status: Closed**
			CIO Cyber Security management will incorporate a plan to identify and assess existing information sharing arrangements with third parties into the Third Party Risk Framework that is currently under development. The plan will include details on how existing key third parties will be identified, riskassessed and documented. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Evidence was not available to confirm that software license compliance was proactively monitored during the audit period.	CIO IT Services management will: • Implement a discovery tool to scan all OPG computers to identify installed software; • Develop and implement a report to identify non-compliance and over licensing; • Establish a process to review the report and address under- or over-licensing. **Status: Closed**
		Some software management process activities were not documented.	CIO Management will issue a comprehensive Software Asset Management Plan (“AMP”), with Corporate and LOB adherence in mind. The Software AMP will describe: • Process for managing and renewing software licenses; • Requirements for Business Continuity per application; • Mechanism to observe/measure/report on software license compliance; and • Process for determining software asset value. **Status: Closed**
22-07 COVID-19 Workplace Safety (ARC 2022 Q1)	Generally Effective (White)	Employees did not consistently demonstrate adherence to certain established enterprise-wide controls.	Observations on the programs identified in this finding will be documented within WebEOC, and considered in each program’s applicability and design to ensure greater consistency in application should OPG implement similar programs in the future. **Status: Closed**
		The process to manage expiring or surplus pandemic Personal Protection Equipment (“PPE”) supplies (masks, hand sanitizers, and face protection) was inadequate.	The Health & Safety Coordinators at OPG facilities will work with site contacts to: • Implement a process to monitor the expiry dates of pandemic PPE supplies; and • Dispose of pandemic PPE supplies that have expired or close to expiry. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Two findings from the 2021 COVID-19 advisory engagement were not fully remediated.	1. Management will review and update the process of admitting new members to the CMCC and IDIRT and direct members to complete the required training. 2. Management will work with the three Business Units to review and update their Business Continuity Plans. **Status: Closed**
22-08 Climate Change Strategy (ARC 2022 Q2)	Requires Improvement (Yellow)	An overarching process was not in place to track progress towards net-zero by 2040.	Management will: • Update OPG's net zero forecast to track the contribution of key initiatives, including projected emissions and reductions. This will be completed every two years, or on an ad hoc basis when any significant changes to expected emissions, key initiatives or major regulatory developments (e.g., finalization of the federal Clean Electricity Standard) occur; • Quantify and update the estimated costs of purchasing offsets for OPG's net zero planning scenarios, as the regulated and voluntary offset market gain certainty. This will include updating and expanding the offset cost analysis currently under development; and • Communicate the information above to the ELT in accordance with the frequency above (i.e. every two years or on an event-driven basis as appropriate). **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Action owners did not consistently provide detailed updates in Asset Suite to enable tracking and reporting.	Management will: 1. Develop a SMART guide to support lines of business to ensure that pertinent climate change actions are specific, measurable, and timely. Annual deliverables and milestones will be defined, where applicable, by line management; 2. Refine the process to ensure that status updates are provided by action owners on a bi-annual frequency within Asset Suite; 3. Incorporate an aggregate summary of climate change action status in the annual CCP status update to key stakeholders; and 4. Document closure notes in Asset Suite, confirming that closed actions are, in fact, complete. This guidance will be included in SMART guide referenced in recommendation #1. **Status: Closed**
		Business units did not always assess potential investments for climate change risks and adaptation opportunities, and risk assessment information entered into the C55 system was not always complete and accurate.	Management will: • Provide additional training to subject matter experts and investment owners on the requirements outlined in governance around when and how to perform climate risk assessments; • Finalize and implement the revised enterprise-wide adaptation strategy within the business; and • Assess the need for and develop processes within C55, where necessary, to further facilitate climate change-related considerations within the investment management process. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Plans for the implementation of certain recommendations by the Task Force on Climate-related Financial Disclosures ("TCFD") were yet to be developed.	Besides the initiatives currently being worked as articulated above, Management will: • Define target completion milestones for the implementation of the remaining TCFD recommendations; • Determine the responsible party within OPG for forming scenario analysis; and • Define climate-related performance targets that align with the company's climate targets and/or goals. **Status: Closed**
22-09 Pickering Inventory Management (ARC 2022 Q4)	Requires Improvement (Yellow)	Inadequate schedule, contingency planning, resources, and organizational change management led to delays in High Impact Team (HIT) initiatives.	Management will: 1. Re-evaluate the timelines of the inventory initiatives and assess resource requirements for the short term to ensure that the initiatives can get back on track. 2. Assess the adoption of project management practices and scheduling applications (e.g., MS Projects) to manage the inventory initiatives. 3. Reassess the role of the third-party consultant to enable the HIT to accomplish their objectives. **Status: Closed**
		The authority to make decisions at various levels within the HIT initiative was not defined, and reporting to oversight bodies was not consistent.	Management will: 1. Assess reasonableness of the HIT Program Governance Framework and update and formalize accordingly, i.e., review and approval expectations around initiative changes, cancellation, and completion, frequency of reporting to oversight bodies, and reporting of relevant metrics. 2. Define what initiative changes are considered significant and the type of decisions that requires the SteerCo's review and potential challenge. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Project teams did not frequently use "Shop at OPG" to utilize PNGS stranded inventory.	Management will: 1. Reassess whether "Shop at OPG" remains an initiative that would yield tangible benefits in managing the PNGS stranded inventory risk, particularly in light of the potential for PNGS redevelopment. 2. Provide guiding principles leading to greater use in certain scenarios (e.g., when an item is in inventory, or when there are similar items in inventory that may be used with minimal design modification without adverse impacts to work programs). This is contingent on the decision to continue "Shop at OPG" as an initiative to be pursued. 3. Complete the "CAT-ID Equivalency" initiative (i.e. I05 and PG10) to develop process, expectations, and barriers to ensure that when parts are ordered, existing inventory is being explored first. 4. Provide communications across the enterprise to create awareness, supplemented with enhanced reporting that is communicated across the business to demonstrate awareness of how much "Shop at OPG" is being used. **Status: Closed**
		The OAR did not contemplate an approval authority process for sequenced enterprise-level write-off initiatives.	Management will: 1. Amend the OAR to include guidance and approval expectations on specific strategic initiatives that would otherwise require Board approval, while still maintaining the control principles embedded within the OAR. 2. Develop a plan to ensure that future writeoffs being conducted as part of inventory management are in accordance with the amended OAR and appropriate approvals are obtained. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
22-11 Market Renewal – Change Implementation (ARC 2022 Q2)	Not Effective (Red)	An integrated resource loaded schedule was not in place to identify interdependencies, critical path, and schedule baselines.	Management will: • Finalize and share with key stakeholders a combined schedule that includes key deliverables, milestones, interdependencies, overall critical path, and resource requirements for the Umbrella MRP; and • Develop the project baseline and key milestones, and begin reporting on progress against them to the MR Integration SC. **Status: Closed**
		Key project activities including market renewal impact assessment and requirements gathering were not completed timely per the milestones defined in the Business Case Summary (“BCS”) and Steering Committee (“SC”) presentations.	In addition to the management action plan articulated in response to finding 1, Management will document the approach and plan to completing and submitting the remaining SRDs and reference level submissions, as appropriate, and communicate it to stakeholders. As of the audit report date, Management has: • Developed and communicated a schedule for completing review and approval of the remaining BRDs, including identification of the resource requirements; and • Issued the detailed design impact analysis document on June 14, 2022 and communicated to stakeholders. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Project performance measures were not defined, progress against milestones was not reported, and not all SC members were included in SC meetings.	Management will: 1. Revise dashboard to show progress on integrated schedule towards defined milestones. Complete definition of performance metrics. Report at monthly MRP Status Update meetings and MR Integration SC meetings. 2. Provide additional information related to the tools and system progress (i.e. IT program) to the MR Integration SC meeting to facilitate its objective to review initiatives associated with Market Renewal and provide feedback / direction; and 3. Ensure that all SC members are invited to future MR Integration SC meetings and quorum be established. **Status: Closed**
		A Project Management Plan (“PMP”), including the gating strategy and risk management plan, was not developed.	With the assistance of the EPMO, management will develop a PMP with the appropriate amount of rigour applied as required by OPG-MAN-00120-00010, including a gating strategy and risk management plan for review, approval and implementation. As of the audit report date, Management has input the program risks into the ePMX tool, including risk assessment and response plans. Risks will be periodically reviewed to assess ongoing effectiveness of mitigation efforts. **Status: Closed**
22-12 RG Turbine Generator Overhaul Program (ARC 2022 Q4)	Requires Improvement (Yellow)	Sampled TG overhaul projects did not consistently adhere to OPG’s project management framework, contributing to adverse project performance.	Management will perform a self-assessment on active TG overhaul projects against key project management governance, identify the gaps, and develop and implement an action plan to close those gaps. **Status: Closed**
			Management will overhaul CPI/SPI metrics reviewed monthly at the RG portfolio, and an action log will be included to capture discussions and corrective actions to address unfavourable trends. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
			Management will finalize and roll out the RG TG Overhaul Program framework document. **Status: Closed**
		The Asset Investment Planning and Management (“AIPM”) software tool is not being fully utilized to support TG overhaul investment optimization and document decision making rationale.	Management will review the calculation methodology of the VF utilized by C55 for valuing TG overhaul investments and make adjustments to address the noted issues, while taking account of experience with the use of C55 by other business units. **Status: Closed**
			Management will finalize and roll out the RG TG overhaul program framework document, which will include a process for documenting the rationale for TG overhaul investment selections in an approved information management system. **Status: Closed**
		A formal change management plan that includes the transition to the Equipment Health Monitoring and Reporting process has not been completed to drive full implementation.	Management will prepare and issue a Change Management Plan for the transition to enhanced Equipment Reliability tools and processes to support timely risk-based decision making. **Status: Closed**
		Three recommendations from the TG Overhaul Strategic Initiative have not been implemented, and actions have not been formally recorded in an approved tracking system for monitoring and closeout.	Management will document all actions associated with the TG Overhaul Strategic Initiative in a managed system, which would facilitate the assignment of action owners as well as formal tracking and closeout of all recommendations and actions including the three outstanding recommendations. **Status: Closed**
22-13 Board of Directors' Expenses	Effective (Green)	N/A: No Findings	N/A: No Findings

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
22-15 DNR Return to Service – Unit 3 (ARC 2022 Q3)	Effective (Green)	Some Systems Available for Service ("SAFS") Open Items were overdue and there were inconsistencies with the target completion date information in the Power BI Reporting System.	Management will: 1. Establish a periodic touchpoint with the Work Management team to review and prioritize: a. The completion of overdue SAFS open items in order to meet milestones requirements; and b. Establish a forum to communicate progress against the workdown of SAFS open items to line management and other stakeholders (as well as highlighting any overdue actions). 2. Implement a process to ensure that all pages within the Return-To-Service Hold Point Dashboard are refreshed and reviewed on a timely basis; and 3. Implement a 'Last Update' date on each PowerBI report to inform readers that the data is current. **Status: Closed**
22-16 Calabogie GS Redevelopment Project (ARC 2022 Q1)	Generally Effective (White)	More detailed design of temporary structures may be necessary during planning to provide greater certainty over project cost estimation and budgeting.	The Project team has documented the upstream cofferdam operational experience as a lesson learned for consideration on future projects. Management will incorporate design considerations for temporary pre-requisite structures as a discrete action for project team assessment in future. **Status: Closed**
		Some instances of changes made to project baseline that impacted cost, schedule, and contingency were not adequately documented.	Management will revise the Project-specific Excel change register log to ensure it is aligned with OPG-MAN-00120-0016. **Status: Closed**
			Management will provide refresher training to the RG PMO team related to the enterprise governance on integrated change control, including an illustrative overview of best practices for capturing details on the CCF. An attendance log will be maintained to ensure the intended audience receives the training. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Pulse reports did not contain fulsome details around minor CPI and SPI variances outside of target ranges, and they did not include planned milestone dates for some reported milestones.	The space constraints in Pulse report templates have subsequently been removed, which will enable more detailed information to be provided. Variance explanations on the Pulse report will be documented prior to the month end close for variances outside of established thresholds. For any milestones that are considered important to disclose in Pulse reports, planned dates for milestone completion will be established and also disclosed. **Status: Closed**
		The Project Management Plan ("PMP") requires updates to reflect the controls and processes in place to manage the Project and OPG's project management framework standards.	The project team will revise the PMP to align with enterprise project management governance. **Status: Closed**
22-18 Darlington New Nuclear Project ("DNNP") (ARC 2022 Q4)	Generally Effective (White)	Some elements of estimate development, review, and validation identified in the PMP were not fully implemented.	Management will update the estimate plan prior to the formation of the Class 3 estimate, and will include enhancements where applicable to specific processes as specified in the recommendation. **Status: Closed**
		The current DNNP risk management practices and activities do not allow for appropriate risk management planning and adequate identification and assessment of risks.	1. The risk management plan incorporated into the DNNP Project Controls Plan will be updated to include all the required information including risk statements, cause and impacts to ensure it aligns with the complexity and cost of the project as well as the IPD model. 2. An initial workshop will be conducted, and future frequency will be based on the need and Phases of the project. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Status of Phase-Gate deliverables were not adequately documented in the program gate packages.	Management will: - Revise the information in gate package 1A to accurately reflect the status of the deliverables; •Document the completion of deliverables from previous gates; and •For future phase-gates, document the rationale for non-completion of outstanding deliverables and the impact and residual risk to the project in the gate package, with actions documented in ePMX. **Status: Closed**
		The logic and location within approved document repositories of estimates and their supporting documentation is not conducive to knowledge transfer and validation of status.	An action will be raised and tracked in EBX to update the SharePoint folders with all relevant documents in an organized fashion that is applicable to the next phase of the project. The folder structure will be aligned to the DNNP IPD WBS and follow IPD Governance Hierarchy currently being established. **Status: Closed**
22-19 Indigenous Relations (ARC 2022 Q4)	Requires Improvement (Yellow)	Evidence to support Financial Settlement Agreements (“FSA”s) and fulfilment of related obligations was not always available.	Management will: • Work with Finance to develop and document a process to track financial and non-financial FSA obligations, recording obligations met (e.g., payments, accruals, and non-financial obligations), and facilitate the retention and retrieval of related documents; • Complete a Records Management Self-Assessment and identify the actions and resources needed to establish a consistent records management system for Indigenous Relations; and • Perform an assessment of the IR team’s resources and responsibilities to identify where there may be gaps and needs for additional support. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Governance does not contain guidance on the preparation of Indigenous Engagement Plans ("IEPs").	Management will establish guidelines on the preparation of IEPs, including but not limited to the identification of the plan owner, the roles and responsibility of key project staff, and a risk assessment of potential adverse impacts. **Status: Closed**
			Management will include descriptions of the roles and responsibilities of key employees involved in Indigenous engagement in the IEPs related to the DNNP, given that project work has already commented in the DNNP while the Hydro Expansion project is still in its feasibility study phase. **Status: Closed**
		Monthly status reports on Indigenous procurement contained inaccuracies.	Management is developing and implementing an automated reporting system to present RAP awards and spend using PowerBI, pulling source data from Ariba rather than AS9. Specifically, the system will: • Pull award data automatically from Ariba into PowerBI to reduce risk of transcription error and include the most recent updates and amendments to purchase orders and contracts; • Pull vendor data from Ariba Vendor Master to ensure that vendors' Indigenous status have been thoroughly validated prior to inclusion in the report; and • For prime suppliers, pull Tier 2 awards through Ariba questionnaire functionality. Documentation from UAT testing will be maintained to support the accuracy of the reporting. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		The interpretation and execution of one RAP target were inconsistent with a plausible interpretation of the wording in the RAP.	Management will: • Review RAP 2023 targets and work with the relevant responsibility centers to ensure that targets are measurable, to demonstrate that completion of the target will contribute to the overall goals of the five pillars of the RAP; and • Determine if the published 2022 RAP needs to be revised for additional clarity. **Status: Closed**
22-20 Generation Revenue Planning (ARC 2022 Q2)	Generally Effective (White)	Release notes describing changes made to the CROP model were not always prepared, and changes to the model were sometimes developed, tested, and implemented by the same individual.	Management will enhance change management processes to enable that: • All changes made to the CROP model will be tested by another individual (i.e. separate from the analyst who developed the changes), and evidence of review will be maintained; and • An email will be prepared for appropriately grouped changes, documenting the change driver, features impacted, and the change approver. **Status: Closed**
		The forecasted impact of unplanned ("forced") outages were not fully incorporated in the hydroelectric generation forecast.	Management will evaluate the suitability of including forced outages into the hydroelectric forecast beginning with the 2023-26 Business Plan. The evaluation will include the following: • Amount of forced outages incurred; • Potential offsetting effect of forced outages on the number of planned outages taken; • The location of the occurrence of outages and water conditions; and • Proper benchmark of forced outages, Equivalent Forced Outage Rate ("EFOR"), forced outage days benchmark compiled by Hydro Optimization, and forced extension to planned outages. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Governance did not exist to guide the hydroelectric forecasting process, and inconsistencies were noted in the forecast review and approval process.	Management will continue to develop the Hydroelectric Optimization procedure document (RG-PROCOP-0011). In addition, management will include the method to document the approval of Hydroelectric forecasts in the document as appropriate. **Status: Closed**
22-21 RWRTRV Station Productivity Initiative (ARC 2022 Q1)	Requires Improvement (Yellow)	Key Performance Indicator ("KPI") reduction targets outlined in the Right Work, Right Time, Right Value ("RWRTRV") Charter were aspirational, and no progressive criteria was established to assess results.	Management will continue to work with site Maintenance managers to further review, develop, and document initiatives which will continue to improve/sustain Maintenance Efficiencies. Part of this review will include the determination of future Maintenance measures and targets. Any revised measure and targets will be included in the 2022 Power BI reporting platform. **Status: Closed**
		Formal close-out of completed sub-initiatives was not performed and documented.	CFAM Management will prepare a close-out report of the completed initiatives and sub-initiatives before year-end. The report will evaluate if the RWRTRV met the objectives; initiatives have been completed and tasks that can be reviewed further; and what went well and opportunities to improve. The report will be presented at a senior leadership meeting (e.g. Site Excellence Meeting). **Status: Closed**
		Some KPIs outlined in the Charter were not consistently reported to the Nuclear Executive Committee ("NEC") as the overall initiative progressed.	Management will, as part of the close-out report, include a summary of the current achievements and progress against the KPI's and where deemed appropriate, document the rationale for dropping KPIs from the original Charter, and report the results to Senior Leadership and other applicable stakeholders. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Initiative-wide risks documented in the Charter were not formally tracked and dispositioned within the initiative risk register.	Management will include the risks from the Charter for the RWRTRV initiative and monitor and respond to these risks if they impact the objectives of the successful completion of this project. The requirement to capture Charter risks in a risk log and where they should be recorded (e.g. ePMX or Sharepoint) will be included in governance and/or guides for future projects. **Status: Closed**
22-23 North American Electric Reliability Corporation (“NERC”) Reliability Standards Compliance – Renewable Generation (“RG”) (ARC 2022 Q4)	Requires Improvement (Yellow)	Issues were noted with supporting evidence used to demonstrate the completion of maintenance activities required by PRC-005-6.	1. Investigate the three representative samples noted within the PNC related to Otter Rapids, Abitibi Canyon, and DeCew 2 sites. Determine root causes and corrective actions necessary to prevent a recurrence, and initiate MACD self reports as required. 2. Implement and issue RG IRCP procedure establishing a continuous improvement process, and complete a IRCP program fleet view dashboard/tool in alignment with the new procedure. 3. Develop RG governance pertaining to PSMP/IRCP work forms, reporting and retention, and establishing a change control process and standardized approach. **Status: Closed**
		Regional Program Execution Plans (“PEP”) spreadsheets for PRC-005-6 lacked justification for extended maintenance intervals and were missing maintenance completion and next verification dates.	Refer to management action plan in Finding 1 above, specifically item #2. **Status: Closed**

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Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Insufficient evidence was available to validate Reported Facility Ratings under FAC-008-5.	Management will develop a comprehensive plan to address the potentially missing ratings evidence and its use, which will involve: • Identification of roles and responsibilities • Perform a gap analysis on the ratings evidence and facility rating sheet • Alignment with existing work/outages/planning • Records retention • Quality Assurance considerations • Enhance facility rating awareness for maintenance and projects staff. **Status: Closed**
22-24 Enterprise Risk Management ("ERM") (ARC 2022 Q3)	Generally Effective (White)	Risk Appetite framework improvements.	ERM will bring back the risk priority statements developed to ERC, and discuss merits of further development of risk priority statements for other enterprise risks. **Status: Closed**
		Enhancements required for linkage between key risks and strategic objectives .	ERM will engage with Strategy team to discuss this recommendation and look to better integrate risk and strategic objectives. **Status: Closed**
		Risk Tolerances not defined for all key risks.	As part of the risk appetite discussion noted in finding #1, ERM will include an update on KRIs to determine if ERC sees value in expanding coverage to include other enterprise risks. **Status: Closed**
		Absence of training plan on ERM matters.	ERM will work with Training and Risk SPOCs to develop a risk management training matrix to define the audience / objective / frequency of training to different BUs and levels of the organization. **Status: Closed**

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Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
22-25 New Horizon System Solutions ("NHSS") Repatriation Strategy (ARC 2022 Q4)	Generally Effective (White)	Project risks and lessons learned were not formally documented, tracked and dispositioned.	Management will review the risks identified and lessons learned and: • Assess whether any issues caused in November could have been avoided if earlier lessons learnt were tracked and communicated better; and • Review 5 remaining open risks reported at the Steering Committee throughout the transition of PWU and establish mitigation plans if any residual risks still exist. **Status: Closed**
22-27 Cyber Security Audit Findings Follow-up (ARC 2022 Q4)	[redacted]	[redacted]	[redacted]

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Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
23-02 IT Project Delivery (ARC 2023 Q2)	Requires Improvement (Yellow)	IT projects that required significant business process change were treated as technology upgrades, leading to inconsistent business stakeholder involvement.	Projects go through an intake process. The project intake form and guidance for the intake process will be updated to reflect a decision point on whether a project would be led by business or IT. The following considerations will be taken: • Complexities of business processes involved; and • Number of business areas affected by the project Once a decision is made all project governance documentation will reflect the decision on a business-led versus an IT-led project. The Project Management Plan (PMP) template will be updated to reflect that the test strategy is acknowledged and reviewed by the business, and that the earliest possible time for business to test the solution is incorporated into the plan. **Status: Closed**
		Insufficient testing of non-functional requirements such as system performance led to performance issues following implementation.	The acceptance criteria for project go-live stated in the Project Management Plan (PMP) template and the Test Strategy guidance will be updated to reflect that non-functional testing is performed appropriately and timely. **Status: Closed**
		Training did not incorporate a hands-on understanding of the new system and focused on online learning.	The Project Management Plan (PMP) template will be updated to reflect that the training strategy and plan will consider the appropriate training vehicle for the change such as hands on training. **Status: Closed**
23-04 Cyber Security Operations Centre (ARC 2023 Q4)	Requires Improvement (Yellow)	The operational performance of both PwC and OPG Cyber Security was not defined, measured and monitored consistently.	Management will work with PwC to define and document operational performance metrics and thresholds which are linked to the contractual arrangement. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
			Management will establish a process to measure, monitor and report on defined metrics periodically against specific thresholds, including actions to be taken if the metrics are off-track. **Status: Closed**
			Management will connect PwC's ServiceNow instance with OPG's once ServiceNow incident management is implemented at OPG to enable the end-to-end event response process. **Status: Closed**
		Approval was not obtained from OPG Cyber Security for Key Positions as defined in the contractual arrangement.	Management will update OPG's process operations documentation to include the approval process over PwC Key Positions and periodic validation that people in Key Positions have been approved. **Status: Closed**
		Some periodic operational reports were not received as required.	Management will update OPG's process operations documentation to include review of PwC reports and escalation with PwC if not received timely. **Status: Closed**
23-05 Renewable Generation ("RG") Work Protection (ARC 2023 Q3)	Generally Effective (White)	Gaps exist with current work protection governance documents.	Management will: • Update the Corporate Work Protection Standard (OPG-STD-0088) to ensure OPG's compliance with the latest version of CSA Z460 and OHSA requirements is clearly demonstrated; and • Update OPG-PROC-0212 to clarify Nuclear and RG WP event response protocol which caused the timeline difference for event categorization. **Status: Closed**
			• Establish a process to track the review progress of AWPPs and AIPs and report the review progress in the quarterly RG Managed System Review Board. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
			Management discussed the PC19 Worker Initial Log requirement for a single worker situation in the CCAG meeting, and clarified that the Worker Initial Log is required when the Holder of Record is different from the single worker, but not required when they are the same person. All work protection coordinators will implement this at their stations. **Status: Closed**
		Inconsistent application of work protection governance for operational activities was identified.	Management will: • Review recent incidents and code coordinator audit findings at monthly WPC site meetings. • Send a quarterly summary of OPG work protection events (LVL 1, LVL2 and selected LVL3/4) to each region for review and lessons sharing. **Status: Closed**
			• Take actions to ensure device code consistency between the MEL and AS9 and address the inconsistent device code issue at Lennox GS. **Status: Closed**
			• Assess the ESM 3R MEL issues at Lennox GS and determine the viability of having equivalent MEL in ESM 3R (in addition to AS9) for the remainder of the RG fleet. **Status: Closed**
		Inconsistent application of work protection governance for oversight activities was identified.	Management will: • Explore Cority functionality to track and assess how timely work protection events are completed (similar to Power BI dashboards); • Develop an action plan to ensure RG could access the WPC database/quarterly assessment reports and have alignment across the organization. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
			• Ensure quarterly assessments are being completed in accordance with OPG-PROC-0214, and that the results are discussed at the site Work Protection Committee meetings, wherein the reports shall include critical evaluation of assessment outcomes and SMART (Specific, Measurable, Achievable, Reasonable, Timely) actions to mitigate trends, or explanation where actions are not required. **Status: Closed**
		Training programs did not include training requirements for all relevant applications.	Management will update training materials for existing training program to include content related to ESM 3R. **Status: Closed**
23-06 Recruitment and Onboarding (ARC 2023 Q2)	Requires Improvement (Yellow)	Inadequate data entry and data validation controls led to challenges with operational oversight and performance monitoring.	Develop a change management plan to increase the likelihood of successful adoption of "Onboard" that will replace the OBC tool. The change management plan should identify and define activities that have been completed such as preliminary stakeholder meetings to define desired end-state activities that are in progress such as development of the tool and future planned activities such as user acceptance testing. **Status: Closed**
			Develop an integrated implementation plan to support Employee Central, Service Now and HR Evolution that outlines the activities, milestones and deadlines for implementing the technology changes. **Status: Closed**
			Implement updated user guides / procedures on the consistent use of MyPower and Onboard for all stakeholders for applicant tracking to support efficient processing, data integrity and R&O measurements and dashboards. Include a sustainment plan with regular review frequency and monitoring of data integrity. **Status: Closed**

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Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
			Create Onboard reporting and data extraction for management oversight of the process and integrate into R&O Dashboard. **Status: Closed**
			Update the onboarding process to transition the Security Clearance verification activity from Recruitment & Onboarding to Security to improve accuracy of verifications and reduce rejections and overprocessing. **Status: Closed**
		KPIs to measure and guide the R&O and security clearance process were incomplete and lacked targets.	Create Recruitment and Onboarding reporting structure and sustainment model that includes defined roles and responsibilities with respect to calculation, collation, reporting, review, decision-making, frequency of reporting and approval of KPI-driven oversight. **Status: Closed**
			Complete Phase 2 enhancements of the R&O Dashboards that include KPIs aligned to components of the R&O strategy, which will provide more detailed operational reporting for R&O managers and workers, Staffing Plan Owners, and leadership oversight. **Status: Closed**
		Systems supporting the security clearance process are unable to generate processing timeline information.	Ensure that the proposed new security clearance management system incorporates the following functionalities: • Reporting a holistic view of the status of security clearance processes; • Automated validation of candidate application quality; • Consider integration of third-party results reporting into new security clearance software; • Consider ways to make the requirement for a paper-copy submission clearer to applicants **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
			Develop a change management plan to increase the likelihood of successful adoption of the new security clearance management system. **Status: Closed**
			Following the implementation of the new security clearance management system: • Establish a process for monitoring security clearances to identify delayed clearances and take relevant actions as needed; • Establish set expected timelines for the components of a security clearance, communicate timelines to relevant stakeholders and follow up where components of the clearance are exceeding expected timelines. **Status: Closed**
		Re-work and some delays in the onboarding process occurred due to a high rejection rate of dosimeter request forms needed for access to OPG sites with the potential for radiation exposure.	Create digital RAD data forms (N-FORM-10019, N-FORM-82452, N-FORM-10692) to minimize errors and enhance accuracy and complete initiative to automate the request approval workflow. **Status: Closed**
		The People and Culture (P&C) Management System documentation requires updates to enable sufficient oversight and operational monitoring.	Complete the update of the management system governance documents to bring governance in line with current processes. The responsibilities of respective groups for onboarding activities should be defined in the updated governance. **Status: Closed**
		Documentation to support hiring decisions was not consistently maintained.	Review the documentation requirements within the recruitment process, and determine whether their retention is essential and update guidance to reflect any items removed. For those that are required, supporting information will be retained in software or tools that support the recruitment and onboarding process rather than in a separate site. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Non-standard security clearance methods were used that are not provided for in OPG's security clearance governance.	Management will: • Ensure that occasional and rare deviations to governance are documented as per N-STD-AS-002. • Consider whether specific exceptions should be added to governance. • Ensure that relevant supporting documentation is consistently maintained in a central location to support security clearance exemptions. **Status: Closed**
		Risks in the R&O process were not documented, identified, tracked, and monitored.	R&O Innovation team will perform a review of the end-to-end R&O process and in collaboration with R&O Management develop a risk register specific to R&O ensuring that it identifies risk owners, risk level, likelihood, risk treatment plans, and action owners. The frequency of review of the risks will also be defined. **Status: Closed**
			Risk-related information, such as target completion dates and action owners, will be retained in Resolver. **Status: Closed**
23-07 Management Compensation (ARC 2023 Q4)	Generally Effective (White)	Planned target distributions are not reflective of actual performance rating distributions for executive employees.	Management will clarify in communications to the HRGC the expectation for executive performance distribution versus non-executive MG bands. **Status: Closed**
		Documentation to justify changes to compensation as a result of revised role accountabilities was not consistently retained.	Management will: • Communicate the amended job accountabilities and salary cap information for the two exceptions to the HRGC; and • Document the assessment that had been verbally conducted for the seven exceptions to maintain a documented analysis. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Access to modify compensation values and configuration was not restricted to key personnel as the list of users was not periodically reviewed.	Management will: • Remove accounts that no longer require access to the Compensation admin functionality; and • Review a log of activity for compensation changes to confirm no unauthorized changes were made. **Status: Closed**
			Management will implement and document a periodic access review of the Compensation module admin group, including a review for unauthorized activity if any removals are identified. **Status: Closed**
23-08 Nuclear Work Order Materials Management (ARC 2023 Q3)	Not Effective (Red)	Lessons learned, performed at the end of each outage or online work, do not review materials ordered versus used.	Management will: Update relevant governance procedures to incorporate a review comparing materials requisitioned with materials consumed. This may include N-PROC-MA-0013, N-PROC-MA-0022, and templates used for lessons learned reviews, ensuring the retention of this requirement for an extended duration and that the outcomes will encompass the implementation of corrective actions. **Status: Closed**
			Management will: Update NK38-MAN-09701-10005 to include the requirement to review whether materials ordered were appropriate. **Status: Closed**
			Management will: Provide senior station oversight of MRNI reduction initiatives through the Senior Work Management monthly meetings. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
			Management will: Provide data on materials requisitioned and not consumed to work groups for evaluation. **Status: Closed**
		Causes and composition of MRNI and Returns have not been identified.	To date, Management has completed a partial analysis of the origins of MRNI and returns, identifying over-ordering by plant operations as one of the main sources. Management will develop an ongoing monitoring process to further assess and mitigate MRNI and returns. **Status: Closed**
			Management will update supporting systems so that selected material requisition actions that are associated with MRNI and returns, require the user to indicate a reason for the action. **Status: Closed**
			Management has restored the permanent linkage between inventory and the originating MR within AS9. **Status: Closed**
		Governance and process documents lack clear instructions and timelines for action on staged materials.	Management will conduct a review of the existing governance documents, including N-PROC-MM-0042 and N-GUID-08173-1008, and update these documents to include guidance for the management of staged inventory. **Status: Closed**

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Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		"On Time Delivery" is not being tracked and monitored.	Management will establish "On-Time Delivery" as a KPI to track and monitor. This will involve designing a method to account for the impacts that have historically skewed the metric (e.g., unrealistic need dates from work groups), and incorporate tracking of vendor lead times to differentiate between different sources contributing to overall lead time. **Status: Closed**
		Key Performance Indicators related to MRNI and Returns reported in the Supply Chain Scorecard were inadvertently miscalculated.	Management will create a Station Condition Record ("SCR") to document the context and remediation activity performed. **Status: Closed**
			Management has rectified the error in the report and briefed staff on the issue for awareness. **Status: Closed**
		Risks with respect to MRNI and Returns are not documented, identified, tracked and monitored.	Management will update the existing "stranded inventory" risk to reflect the impact on the risk from MRNI and returns, and document mitigating activity, related to MRNI and returns, in the remediation plan for that risk. **Status: Closed**
23-09 Pickering Outage Management (ARC 2023 Q3)	Effective (Green)	Outage management protocols for instances where Planned Outages transition into a Forced Outage are not defined in current governance.	Management will update existing governance to clarify applicability along with required project management elements involved in the execution of a Forced Outage immediately following a Planned Outage. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
23-10 Corporate WANO Peer Review – Follow Up (ARC 2023 Q2)	Generally Effective (White)	Station key performance indicator ("KPI") targets that were not aligned with comparable Industry Top Quartile ("ITQ") targets were not consistently approved or supported with a documented action plan or justification memo.	Management will: 1. Update N-PROC-AS-0080 Nuclear Business Planning procedure to clarify instructions and annual requirement to have KPI justification memos approved by the Chief Nuclear Officer for KPI targets on nuclear station industry performance reports that do not meet ITQ targets for the Business Plan's budget year (i.e., first year of the Business Plan). **Status: Closed**
			Management will: 2. Initiate SCRs to correct the two PNGS targets that were incorrectly entered into the Enterprise Performance Reporting system. **Status: Closed**
		Proficiency levels and succession planning of the corporate oversight roles are not formally assessed and monitored.	Management will develop and document a CFAM proficiency heat map process in a nuclear guide which will be referenced in relevant job guides. The CFAM proficiency heat map with specific assessment criteria will be used to support identifying gaps in proficiency, building tailored CFAM learning, and planning succession and transition. **Status: Closed**
23-11 Asset Management & Maintenance Strategy (ARC 2023 Q2)	Requires Improvement (Yellow)	There is no formally documented plan to reduce WOT backlogs for RG, including key performance indicator ("KPI") targets and timelines.	Management will: • Revise work management governance to include direction/expectations for monitoring and management of WOT backlog on an ongoing basis. • Include a WOT Backlog Reduction measure as a KPI within RG's performance metrics and reporting. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		KPIs have not been implemented for the Asset Management Program.	Management will identify and use the key success factors impacting asset management to develop and implement appropriate KPIs to improve the asset management function at OPG and performance reporting to senior leadership. **Status: Closed**
		Changes to RG's COLM Technology Implementation project did not follow the change management process, and the project was missing key project management controls.	Management will: • Perform a detailed assessment of the current project status against the governance requirements and to develop a recovery plan that addresses the specific individual gaps, which will include alignment with the BCS and development of a Project Management Plan and revised cost and schedule baselines. • Implement the recovery action plan developed above. **Status: Closed**
			Management will: • Implement the recovery action plan developed above. **Status: Closed**
		Value Based Maintenance ("VBM") principles have not been formally documented in maintenance governance for Nuclear and RG.	Nuclear Management will update N-PROC-MA-0020 Predefined Process and the Preventative Maintenance Review Board's Term of Reference to outline the key steps to integrate VBM in the maintenance process. **Status: Closed**
			RG Management will update RG-PROG-MA-0003 Work Management Program to specifically include cost and value considerations (e.g., cost-effectiveness, cost monitoring, rationalization of PM program changes) in the ongoing implementation of the program. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Some maintenance work order ("WO") priority levels were not accurately assigned by RG Work Centres.	Management will implement a reporting process for monitoring and oversight of WOTs, with a focus on P1, to ensure ongoing appropriate prioritization. **Status: Closed**
23-12 Darlington Nuclear Refurbishment ("DNR") Claims & Disputes (ARC 2023 Q1)	Generally Effective (White)	There was insufficient documentation to support the closure of some issues and claims.	Management will: • Assess potential software tools to determine a sustainable and efficient issue documentation and tracking system. • Update the governance to provide specific guidance on document retention (e.g., defining significant emails) and the level of detail to be captured on the issue management log. **Status: Closed**
		Some Commercial Management staff did not complete the required training.	Management will ensure that, as part of the governance initiative, training timelines are included in governance to ensure a consistent expectation related to training requirements. **Status: Closed**
			Management will also: • Roster the two staff members to complete outstanding training. • Work with the MyPower Administrator to automatically mandate new CM employees to complete within a specified period. **Status: Closed**
		Some governance documents were not updated to reflect current Commercial Management practices.	Management will: • Perform an extent of condition assessment and update all governance accordingly; and • Create and implement a plan to educate the Commercial Management team and establish periodic training for employees, including a plan to review governance on an established interval. **Status: Closed**

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Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
23-13 Darlington Nuclear Refurbishment ("DNR") Billings (ARC 2023 Q3)	Generally Effective (White)	Some inconsistencies were found between timesheets and labour billing packages for the TG Engineering Services Equipment Supply ("ESES") Agreement around hourly rates and type of time.	Management will: • Assess the extent of testing of labour charges in future Post-Payment Audits to provide adequate coverage of billing areas that are more susceptible to error/manipulation based on a risk assessed determination; and • Work with GE to increase sub-vendor billing transparency and obtain support to validate the hours charged on OPG projects where applicable. **Status: Closed**
		Post-Payment Audit review cycles documented in governance were not reflective of how audits were executed in practice.	Management will complete the update to the Post Payment Audit Program Plan governance to define the current process for determining audit cycles. Where the approach differs across bundles, the governance should be clear on how each is treated along with rationale for the approach taken. **Status: Closed**
		There have been delays in ES MSA contractor payments, including invoices relating to DNR.	Management will review and update the weekly aging distribution list to ensure that delayed invoice metrics are being communicated to the appropriate individuals for use in project oversight. Management will also revisit after a period of six months and consider whether additional actions or project reporting on metrics is required. **Status: Closed**
			Management will conduct an assessment to identify common themes and causes resulting in delays and consider procedures and/or technology solutions that can reduce review and approval timeframes. **Status: Closed**

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Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
23-15 Quality Management Program (ARC 2023 Q3)	Requires Improvement (Yellow)	Effectiveness reviews of self-assessments were not executed in line with governance.	Management will: •Prepare a Self Assessment Plan for the CCoE Division and add an assessment for the QM group; and •Create prompts in AS9 to ensure divisional self-assessments are not missed going forward. **Status: Closed**
		The severity levels of some observations created to capture negative trends were not elevated as required by governance, and medium level observations were closed without raising a Station Condition Report or Correction Action Report.	Management will reassess current and outstanding trends and elevate the observations with higher severity levels as appropriate. Follow up actions for these observations will be documented, if needed, and dispositioned. **Status: Closed**
			Management will update governance to: •Require that details of observations include criteria, cause, and impact so that there is sufficient and transparent information to demonstrate how severity levels were assigned and meet the established criteria; •Establish a process to address situations where discretion is exercised in assigning a severity rating or closing an observation, and treat such discretion as exceptions to the normal course process within the QM program; and •Require review and approval of documented exceptions where discretion is exercised. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Accurate information on the start and end dates for program windows was not consistently available, presenting challenges in assessing adherence to timelines established within governance for the preparation of oversight plans and reports.	Management will: •Revise the QM planning process, including the development of key tools (i.e., Annual Plan) and deliverables (observation reports) to track and record program window date changes (i.e., to the T10 schedule), and the potential impact on surveillance resourcing and scheduling; and •Revisit timing requirements for planning and preparation to ensure execution of activities are adaptive to schedule changes. **Status: Closed**
		The Annual Plan was not consistently updated with rationale to explain the non-selection of certain program windows for surveillance.	Management will: •Revise governance to require a rationale to be provided for program windows that are not selected for surveillance activities; and •Include functionality in the Annual Plan spreadsheet to require mandatory documentation of the rationale for non- selection. **Status: Closed**
		QM plans and reports were not consistently communicated to relevant stakeholders.	Management will: •For QM quarterly reports, develop and provide targeted communication that will allow senior leadership a succinct view of the status of QM's activities; •For horizontal assessments, provide results to relevant stakeholders through a review check. The review will also ensure that evidence of communication is retained in a central repository; and •Revise guide requirements for communication of oversight plans and reports as this information is available to stakeholders because it is published on the QM site. Management will recommunicate the availability of this information to project stakeholders. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
23-16 Darlington New Nuclear Project – Validation Phase (ARC 2023 Q4)	Generally Effective (White)	Recovery plans related to the validation phase goals did not meet the requirements of the DNNP Project Controls Plan.	Management will amend the DNNP Project Controls Plan to introduce additional scalability and flexibility to the recovery plan timelines, commensurate with the assessed criticality of the milestones. **Status: Closed**
			Management will select a tool (and provide training to relevant employees on the requirement of using the tool to record and track recovery plans including actions required to close the recovery plan. **Status: Closed**
		The DNNP has not developed a sustainable process to assign, deliver, track and manage training.	The DNNP team will select and implement a training platform that will enable the project to assign, deliver, track, and manage training for OPG and the non-owner partners in an integrated manner. **Status: Closed**
		Some risk management governance requirements are not being completed or effectively rolled out.	The DNNP team will complete the initiative that addresses the risk exposure period for all risks in EBX and add actions for all risks that are related to the current validation phase. Subsequently, once the project schedule is complete, the DNNP team will complete the risk exposure period in EBX for all risks. **Status: Closed**
			The DNNP Risk Management Plan will be updated to require that the rationale to support changes to current risk score is documented and reviewed for accuracy in EBX. Once the changes are reviewed in EBX, the change will be reflected in the Risk Evolution Report. **Status: Closed**

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Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
			The DNNP team will formalize a review process, including a control to detect instances where 3-point estimates have not been completed, to ensure greater completeness of risks into the QRA. **Status: Closed**
		Lessons learned that could be gained from closed issues were not consistently documented and new issues were not communicated in a timely manner.	Management will review and revise, as needed, the DNNP Issues Management Instruction to determine if it is too prescriptive with lessons learned and new issue communication timeline. **Status: Closed**
23-19 Nuclear Sustainability Services (ARC 2023 Q2)	Generally Effective (White)	There were gaps in process and control design over shipping records being electronically uploaded to system tools that pose a risk over completeness of data.	Management will: 1. Perform reconciliations of shipping records between manual SAFs and system tools (i.e., ESAF and AIMS) by obtaining manual SAF information from all OPG shippers on a quarterly basis; and 2. Perform a reconciliation of shipping records between ESAF and AIMs on a monthly basis. 3. Implement an initiative to enhance the ESAF system with the goal to obtain AIMS qualification and subsequently supersede AS9 for RMT shipping information. **Status: Closed**
		Some non-OPG carriers performing transportation services for radioactive materials do not have quality assurance programs that have been reviewed by OPG.	Management will: 1. Expedite the Document Change Request (“DCR”) over RMT governance as an urgent priority. 2. Define Quality Assurance (“QA”) program requirements governing the transportation services of radioactive materials. 3. Update OPG-FORM-0210 & OPG-FORM- 0214 based on the defined QA program requirements in action #2 above. 4. Restrict the ability of shippers to add vendors within the ESAF system. **Status: Closed**

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Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		The number and role of administrators supporting the ESAF system was not aligned with leading practices.	Management will change the personnel provided with administrator access to three roles outside of the ESAF process: the RMT Section Manager, First Line Manager Civil Maintenance, and a representative from Radiation Protection. **Status: Closed**
		The benefits outlined for some NSS strategic initiatives were not forecasted or quantified.	Management will: 1. Create a N-GUID for development of NSS Strategic Initiative Charters, that incorporates a graded approach (based on Complexity versus Impact), which will provide guidance on quantifying and forecasting the expected initiative benefits, to aid with measuring initiative success during the initiative and/or at closeout. 2. Update existing and relevant Charters due for annual revision, by applying the new N-GUID to enhance existing benefit details. **Status: Closed**
23-20 Ring-Fence – Bruce Power (ARC 2023 Q1)	Generally Effective (White)	There were some instances of non-compliance with ring-fence training requirements.	Management will: • Use the newly implemented mARS system configured for the ring-fence to check that users have completed the required training, before being eligible to apply for ring-fence membership. **Status: Closed**
			Management will: • Implement monthly verification of EM employees' training credits and ensure linkage of Qualification ID before adding the employee to the EM lists. **Status: Closed**
			Management will: • Work with the training owners and the TIMS Administrator to program TIMS to mandate new EM employees to complete ring-fence related CALS within 30-days of joining EM. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Ring-fence governance requires review and updates.	Management will ensure that noted sections of OPG-PROC-0002 are updated. **Status: Closed**
23-21 Ring-Fence – Atura Power (OPG Employees) (ARC 2023 Q1)	Generally Effective (White)	There were some instances of non-compliance with ring-fence training requirements.	Management will: • Use the newly implemented mARS system configured for the ring-fence to check that users have completed the required training, before being eligible to apply for ring-fence membership. **Status: Closed**
			Management will: • Implement monthly verification of EM employees' training credits and ensure linkage of Qualification ID before adding the employee to the EM lists. **Status: Closed**
			Management will: • Work with the training owners and the TIMS Administrator to program TIMS to mandate new EM employees to complete ring-fence related CALS within 30-days of joining EM. **Status: Closed**
		Quarterly attestations were not consistently received from OPG employees seconded to Atura.	Management will: • Include a due date on the attestation and implement a weekly follow-up with secondees; and • Incorporate into the process validation of the completeness of the list of seconded employees with OPG HR prior to sending attestation requests to employees. **Status: Closed**
		The ring-fence governance document requires review and updates.	Management will ensure that noted sections of OPG-PROC-0002 are updated. **Status: Closed**
23-23 Board of Directors Business Expenses (ARC 2023 Q1)	Effective (Green)	N/A: No Findings	N/A: No Findings

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Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
23-26 Fund Management (ARC 2023 Q4)	Generally Effective (White)	System and Organization Controls ("SOC") reports from some third-party service providers were not reviewed, and daily monitoring of fund's compliance with approved risk tolerance guidelines was not consistently performed due to data unavailability.	Management will: Complete review of SOC reports as received for GSAM and BNY Mellon. Assess whether the 5-day breach window is appropriate and practical for monitoring and make any relevant updates to the GIPP. Formalize a contingency plan to address data unavailability to ensure alternative monitoring activities can occur. **Status: Closed**
		A risk compliance log was not maintained and an annual update on Investment Manager compliance was not reported to the Investment Committee (IC)	Management will assess whether existing practices surrounding the Fund's risk and performance are aligned with best practices. Subject to the outcome of the assessment, Management will either: • Update the GIPP to remove references to the compliance log and clarify which Investment Manager compliance exceptions are required to be reported to the IC; or • Prepare and maintain a compliance log that documents risk tolerance escalations and resolutions, and ensure that all instances of non-compliance are communicated to the IC. **Status: Closed**
		An independent assessment of the Investment Strategist's performance was not formalized or documented.	Management will: • Develop and implement a formal process for reviewing the Investment Strategist's performance; and • Communicate independent assessment results to oversight bodies and the Investment Strategist annually. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		A formalized process for valuation of direct investments is not consistently followed.	Management will: • Update the GIPP to require a formal valuation memo to be completed for illiquid investments to support OPG-generated values; and • Review and assess whether additional considerations should be included in valuation memo template for potential value-impacting factors (e.g., discounts for minority shareholdings). **Status: Closed**
23-28 Market Renewal Program (ARC 2023 Q4)	Requires Improvement (Yellow)	Business requirements of the Lepton suite development were not clearly traced, and schedule changes were not assessed and controlled to ensure timely delivery.	Management will develop a project plan for Lepton suite scope and schedule management, establish the scope performance baseline, and maintain the Requirement Listing for scope assessment and management. **Status: Closed**
			Management will take actions to improve ADO traceability (e.g., updating naming convention, document Business Requirement Document (“BRD”) IDs, and building queries). **Status: Closed**
			Management will include an integrated UAT (User Acceptance Testing) testing for all business requirements at an appropriate time in the project schedule. The integrated UAT testing will provide assurance on realization. The appropriate timing will ensure that the Lepton suite team has sufficient buffer time to remediate in case there are any missed business requirements. **Status: Closed**
			Management will develop more ADO dashboards for progress tracking and include appropriate status updates in the monthly reporting. **Status: Closed**

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Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Project management plans and the integrated project schedule were not kept up-to-date, project performance metrics have not been consistently published, and reported earned value metrics were not reflective of deliverables completed for the MRP Umbrella project.	Management will complete the work on integrated schedules and build performance dashboards accordingly. Upon completion, the MRP Umbrella and IT projects will follow EPMO governance for project management and reporting. Amendments to the methodology applied in calculating earned value will also be addressed through this management action. **Status: Closed**
			Management will update the risk management plan and adjust risk reporting accordingly. **Status: Closed**
			Management has developed a project governance change registry to capture changes for updating the PMP. The registry is a living document which will also serve as interim governance until the updated PMP is issued. **Status: Closed**
			Management will update the PMP to address hybrid tool changes. **Status: Closed**
		The scope and schedule of the business process redevelopment initiative were not well defined and tracked for timely completion.	Management will revise the TOR to contain the elements of a project plan and schedule with greater definition, which will be shared with relevant stakeholders for alignment and used to guide execution and tracking. **Status: Closed**
23-31 Third Party Risk Management (ARC 2023 Q4)	Requires Improvement (Yellow)	A central list of third parties with access to OPG systems is not maintained, and there are no formal processes to inform DTS of offboarded vendors to initiate revocation of access to OPG systems.	Management will establish a process to ensure that communication is made to necessary OPG teams to inform them of required actions to be executed upon communication of the end of vendor relationships. **Status: Closed**

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Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
			Management will review active accounts with non-OPG email addresses and third parties in Active Directory to confirm adherence to established practices (i.e., expiry dates for accounts). **Status: Closed**
			Management will develop a sustainable solution in the form of an Identity Access Management ("IAM") tool which will help track activity and manage risks associated with vendor access. **Status: Closed**
		Supply Chain does not currently have a centralized process to proactively monitor and translate global market and geopolitical trends into potential impacts on projects and outages.	Management will define a formal plan, based on a cost-benefit analysis, which includes the objective and deliverables of a centralized process to proactively monitor and translate global market and geopolitical trends of most significance to OPG into the potential impact on projects and outages. **Status: Closed**
		Cyber risk assessments are not conducted during the vendor needs identification phase of the Request for Proposal ("RFP") / Request for Quotation ("RFQ") process.	Management will: • Update procurement governance with procedures to involve the Cyber Security team to perform due diligence assessments during the vendor needs identification phase based on defined criteria; and • Communicate the updated governance and new procedures to procurement specialists, BUs who are actively involved with procuring services, and establish appropriate training. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Cyber Security does not have oversight of non-requisition purchases.	Management will enhance detective controls and exception reporting to provide adequate oversight over non-requisition purchases, in line with the established risk tolerance levels and/or establish the company's cyber risk posture to non-standard purchases. **Status: Closed**
24-01 Artificial Intelligence ("AI") Governance (ARC 2024 Q1)	Requires Improvement (Yellow)	AI strategy and central governance, including roles, responsibilities and accountabilities of stakeholders involved in AI governance and the end-to-end management of AI systems, are not clearly defined.	Within the organization's overall digital strategy, Management will define the role of AI, with defined AI roles and responsibilities, accountabilities and risk appetite. Management will develop an AI development lifecycle process document that provides guidance to users on roles and responsibilities and all the steps and deliverables that need to be followed across the AI life cycle. This document will be referred to in the 'Usage of AI' ToR. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		A talent development program that integrates AI training, knowledge transfer and people management practices to effectively leverage AI technologies is not in place.	Management will develop a knowledge transfer strategy for AI Committee members. This will involve identifying potential successors for each role on the Committee, while considering the specific skills and expertise required to continue AI advancement. Management will establish mandatory training programs on AI definition, AI risk appetite and tolerance, AI development, AI risk management, AI third-party risks and Responsible AI principles. The training will be customized for each stakeholder group (e.g., LOBs, AI Committee, AI CoE, and second line oversight functions) based on the level of AI understanding required for their roles and responsibilities. Management will define AI training as part of the AI strategy and roadmap and document and review training content, monitor training completion and consider completion as a qualification for individuals involved in AI decision making processes (e.g., LOBs, AI Committee, AI CoE, and second line oversight functions). Training materials will be customized based on the audience (end users versus developers). **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Current AI processes and procedures, including performance and progress monitoring of AI systems, lack the necessary rigor to ensure consistent adherence to AI governance.	Management will establish a process to identify and document AI projects and third-party AI solutions that have not been presented to the AI Committee. Management will update the AI inventory and capture the owner, data sources, algorithms, users/LOBs where an AI system is deployed and the monitoring cadence for all AI systems. AI Governance and Oversight Model will be finalized, taking into consideration: • The roles and responsibilities of the AI Committee; • The impact of non-compliance to the IT PMO and AI Committee processes and communication to the appropriate stakeholders; • The need for a complete AI inventory, including shadow AI systems; and • A process to monitor all AI systems across OPG centrally to validate that AI models are performing appropriately. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
			Management will notify the procurement team of AI system procurement requests to validate appropriateness. Management will perform a retroactive review of all AI systems identified prior to the AI Committee's establishment that are currently being developed or have been deployed to validate their alignment with the most up to date AI governance processes. Management will develop a model card for each AI use case to document the following: • How well the model performs compared to performance metrics; • The AI risks, benefits, acceptable error rates and monitoring cadence; • Assigned owner of the model card; and • Inclusion of ROI against defined project success metrics (for AI use cases with significant investments) Management will indicate dated reviews and approvals for all documents and assessments associated with the planning, design, development, deployment of AI systems. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Centrally managed AI risk management processes for all use cases have not been established.	Management will revamp its AI Risk Impact Assessment questionnaire to holistically address the risks identified in the Responsible AI principles, including considerations of risk tolerance for each AI use case, and develop a user guide for the questionnaire to provide helpful instructions to respondents on appropriately evaluating all AI risks. Management will develop a formal process to assess third-party AI risks based on existing TPRM processes and the AI questionnaire. The assessment will be documented in the TPRM standard, applied to all third-party AI systems and vendors and will include details on third-party systems and their data. **Status: Closed**
		Existing AI procedures and documents have not been updated in a timely manner to incorporate relevant documentation references.	Management will update existing AI policies and procedures (e.g., 'Usage of AI' ToR, Responsible AI principles and risk assessment procedures) to reference existing risk policies (e.g., OPG-PROG-0042 Cybersecurity, OPG-STD-0181 Third-Party Risk Management, OPG-PROG-004 Enterprise Risk Management, etc.). Management will define a regular cadence for revising the 'Usage of AI' ToR and 'AI Committee' ToR, (including updating the individuals representing the AI Committee). **Status: Closed**
		Table-top exercises on AI related incidents and crises have not been conducted with relevant AI stakeholders.	Management will conduct table-top exercises with the LOB, AI Committee, AI CoE and other relevant stakeholders / AI users on incident and crisis response planning and procedures. The table-top exercises will cover the roles and responsibilities of all the individuals involved in responding to an AI related incident or crisis and include information on "shut-down" and decommissioning procedures. **Status: Closed**
24-05 Ethics Hotline / Complaints Process and Reporting (ARC 2024 Q4)	Effective (Green)	N/A: No Findings	N/A: No Findings

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
24-06 Equity, Diversity, and Inclusion Strategy (ARC 2024 Q3)	Generally Effective (White)	ED&I Strategy actions are not directly mapped to specific GDEIB key areas and benchmarks to enable assessment of progress on achieving OPG's 2030 commitment.	Management will map actions from the action tracker against the ED&I Strategy and to the GDEIB key areas/benchmarks to enhance measurement and tracking for reporting to key stakeholders. **Status: Closed**
		The risk and impact of outstanding actions on the achievement of the ED&I Strategy have not been formally assessed, including the development of mitigation actions.	Management will perform a risk assessment on outstanding actions to evaluate the potential risks and impacts of non-completion and based on the outcome of the assessment, develop mitigation actions for at-risk items. **Status: Closed**
24-08 Long Lead Material Procurement & Supplier Capacity Risk Mitigation (ARC 2024 Q2)	Requires Improvement (Yellow)	End-to-end processes, responsibilities and use of systems to enable the development of procurement strategies for demand identification from potential investments are not clearly defined or accepted by business units.	Management will establish and document the desired end-to-end process and secure enterprise-wide alignment of the responsibilities for early demand identification and supplier capacity risk mitigation. Governance documentation will be updated where applicable. Supply Chain Management will: • Attend the AMOC meetings to provide procurement input; and • Determine the extent and granularity of data needed for the chosen solution to provide advanced demand signals. **Status: Closed**
			Asset Management will: • Ensure future procurement information are captured in a consistent, complete, and detailed manner; • Implement solutions to ensure demand signals are available to facilitate Supplier Capacity Risk Mitigation; and • Invite Supply Chain to the AMOC meetings and obtain input. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Dispositions for supplier capacity risk mitigation actions are not consistently documented, and steady-state process is not yet determined to ensure periodic refresh of demand data and reassessment of risk mitigation plans.	Management will: • Capture lessons learned regarding the expectation on dispositioning of supplier capacity mitigation actions; • Incorporate Capacity Risk Management process into governance and develop plans to transition the practices into the annual Enterprise Procurement Planning for steady-state support; and • Update OPG-PROC-0211 section 1.4.4.4 as necessary to clarify the expectations around the expectations around category strategy documentation. **Status: In-Progress**
24-09 Supplier Relationship Management (ARC 2024 Q4)	Generally Effective (White)	Completion of deliverables outlined in the SRM initiative plan is delayed, the number of completed supplier scorecards did not meet the planned target, and related performance management activities were completed to a limited extent.	Management will: 1. Update the SRM Initiative Plan with a roadmap and schedule that outlines the timelines for all remaining activities and deliverables; and 2. Establish formal periodic SRM status reporting to Supply Chain Senior Leadership, including requests for approval to key changes to the SRM initiative. **Status: In-Progress**
			Management will: 3. Establish a formal structure to document all supplier development plans with a tracking tool. **Status: Closed**
		The current supplier scorecard lacks a key ESG metric, and there is no alternative process in place to evaluate suppliers that do not have ESG information in the data source	Management will: 4. Update the one supplier scorecard to include information on Human Rights results and actions. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		used by Supply Chain.	Management will: 1. Obtain confirmation of completed EcoVadis registrations for the four noted suppliers; 2. Determine an evaluation process for suppliers who have not subscribed to EcoVadis or have declined in rating so they will be appropriately evaluated; and 3. Update the supplier scorecard template to incorporate Human Rights performance metrics. **Status: In-Progress**
		Supplier scorecards are not stored in Ariba as required by governance, and the SRM Process is not documented at the appropriate governance level of authority.	Management will: 1. Assess all documents generated by the SRM process, including scorecards, to determine which should be treated as records, and revise governance accordingly; 2. Store SRM documents that are deemed records per the revised governance in the designated repository; and 3. Establish a governance framework for the SRM program and update the governance accordingly. **Status: In-Progress**
24-10 Corporate Headquarters Project (ARC 2024 Q3)	Generally Effective (White)	A Program Management Plan and a Level 2 schedule were not prepared to manage the full scope of the CHQ Program.	Management will assess whether developing a Program Management Plan and preparing a Level 2 control schedule covering the full program scope is beneficial, given that the project is already in its execution phase. Based on the outcome of the assessment, the necessary documents will be created, or an exemption will be sought from the Project Sponsor to forgo the creation of these documents. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		The CHQ Program Charter was not formally approved by the Program Sponsor and stored in an Approved Information Management System, and not all program risks are recorded in an approved risk management system.	Management will: • Update the CHQ Program Charter, obtain the Program Sponsor's approval, and file it in an AIMS; • Assess whether all CHQ program risks should be documented in an approved risk management system. Based on the outcome of the assessment, either document the risks in an approved risk management system or seek an exemption from the Project Sponsor to continue retaining them in SharePoint; and • Update the Campus Headquarters Renovation Project Management Plan with the correct document number. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
24-11 Employees' Business Travel & Expenses (ARC 2024 Q3)	Requires Improvement (Yellow)	Certain expenses were approved not in accordance with the Standard and related policies.	Management will develop and communicate a plan to require mandatory completion of the OPG Business Travel & Expense training course for existing managers, administrative staff, and new hires, and for annual refresher training to be conducted to highlight changes to Concur and the Standard, as required. As part of the training, approvers will be reminded of their responsibility to thoroughly review expenses, exception reports, and take follow-up action. Management will revise the Standard to describe exception reports and related line management responsibilities in more detail, which will also be reviewed as a topic in the mandatory training. Management will ensure that all P-Cards will remain blocked, and related communication will be sent to impacted employees. A semi-annual review will be conducted for unblocked P-Cards to ensure there remains valid and documented justification. Management will assess the implementation of additional controls and reporting capability in SAP Concur to prevent and detect user errors over group meals and facilitate compliance and exception reporting. Management will contact the relevant employees regarding the exceptions and will seek reimbursement. **Status: Closed**
			Management will develop quarterly reports that highlight significant exceptions, which will be provided to Enterprise Leadership Team ("ELT") members to action and follow up with support from Controllership. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Practices related to oversight and follow-up actions on reports identifying potential exceptions and non-compliance are inconsistent with the expectations outlined in the Standard.	Management will revise the Standard to clearly outline that line managers, instead of Controllership, have direct accountability and responsibility to review the exception reports and follow up on exceptions. **Status: Closed**
			For a period of 12 months, Management will conduct a random sample of 10 exception reports on a quarterly basis. Key findings will be reported to the ELT for awareness. **Status: Closed**
		OPG's Standard does not provide detailed guidance over certain types of expenses, some of which have prescriptive requirements within the Directive.	Management will update the Standard to align with the Directive, as follows: a) Include additional guidance on meal allowances by specifying the required 24km travel distance to claim meal expenses for management; and b) Revise the mileage policy to provide a clear and detailed explanation of incremental travel. Management will work with stakeholders to configure the Concur tool so that the automated calculation of mileage based on the inputted data incorporates the incremental travel formula. Once completed, the change will be communicated to all employees. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		One instance was noted where an expense was not reported to the Office of the Integrity Commissioner ("ICO") and some instances were noted related to summation errors.	Management will notify the ICO of the error and will revise and resubmit the summarized total amount for the Top 5 employees for 2023, including all supporting receipts and details to facilitate their review. Management will update the reporting logic to pull from the source system (Concur) thereby ensuring summarized totals match expense claims. The first report will be generated in early 2025, and in the interim a cross-checking review process will be implemented. **Status: Closed**
		There is a lack of detailed vendor reporting for corporate card delinquency charges beyond 60 days.	Management will run the aging delinquency report (greater than 61 days) on a monthly basis and will follow up with employees directly to ensure all outstanding balances are paid by the employee and OPG does not incur any costs. **Status: Closed**
24-12 Strategic Outage Planning (ARC 2024 Q3)	Generally Effective (White)	The scope of the D4F Planned Outage Duration Improvement sub-initiative has not been clearly defined and documented, and risk management practices do not allow for adequate identification, assessment, and monitoring of risks.	Management will: • Develop a D4F Planned Outage Duration Improvement sub-initiative scope document that describes the outage activities and process to be followed to achieve a 40-day critical path outage duration; and • Perform a formal risk assessment for the D4F Planned Outage Duration Improvement sub-initiative and based on the results, identify, assign and document risk owners, mitigation actions and due dates in the form of a risk register (i.e. Resolver), which will be reviewed and monitored on a regular basis (e.g. annually in D4F Oversight Committee meetings). **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		A clearly defined schedule baseline, including a process to formally track schedule performance metrics for the sub-initiative, was not developed.	Management will define the schedule baseline for the D4F Planned Outage Duration Improvement sub-initiative with target completion dates, schedule baseline, and resource planning (including schedule performance metrics). **Status: Closed**
		The D4F Initiative Terms of Reference is not maintained in OPG's Approved Information Management System.	Management will update the D4F Initiative Terms of Reference to include an appropriate document number and revision history, and upload to an Approved Information Management System to align with the requirements of OPG-PROG-0001, *Information Management*. **Status: Closed**
24-13 Severe Weather Preparedness (ARC 2024 Q2)	Requires Improvement (Yellow)	Both Dam Safety and Facility-Level Emergency Preparedness & Response Plans ("EPRPs") do not contain plans or procedures for handling certain adverse weather conditions, including wildfires.	Management will review which regions require specific plans and procedures for certain severe weather events, based on readiness discussions, experience from recent events, and routine exercises in consideration of regional risk profiles. Prior to the Target Completion Date, each RG operation group will identify back to the Director, Dam & Public Safety what specific plans and procedures (if any) are required to be prepared along with proposed timelines. By the Target Completion Date, timelines for completion of the plans and procedures will be mutually agreed to by the operation group management and the Director, Dam & Public Safety. **Status: Closed**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Assessments of post-exercise and real event observations in After Action Reports (“AARs”) focused solely on items mandated by prescribed governance without considering their impact, while Corrective Action Plans (“CAPs”) were not added to the RG tracking module in a timely manner.	Management will: • Update Section 11.2.5.3 of Standard 11 to ensure that the impact from observations in the AARs are given more prominence when defining observation categories; • Update governance to ensure that AARs clearly indicate which actions (i.e., CAPs) will be undertaken as an outcome of the report and all observations have been clearly dispositioned; and • Review existing Emergency Management OFIs to determine if any should be elevated to “Finding” or “Significant Finding” based on their impact, and document CAPs as appropriate. If the proposed update to RG-PROC-AS-0002 requiring CAPs to be created within 90 days of the After Action Report does not come into fruition, Dam & Public Safety Management will include in their governance clarifying that the CAPs are to be created within 90 days with an action plan identifying deliverables and target completion dates. **Status: Closed**
		Some governance provisions related to the conduct of tabletop exercises were not followed.	Management will update governance as follows: • Create an “all-hazards” tabletop subsection which details frequency, participant, objective and process requirements; • Revise the language regarding the invitation of external copy holders to “classic” tabletops in Section 5.8.2 of Standard 8; • Clarify the inclusion of tabletop exercises at coordination/stakeholder meetings in Section 5.7; and • Document clear instructions for facilitators on what should be done after questions or discussions occur during exercises to provide a reasonably consistent result. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Communications with external stakeholders were inconsistently or inadequately performed.	Management will create an outline document to be used when planning coordination/stakeholder meetings, which references the six discussion requirements required by Standard 8. Management will review and update CAL 76288 to stress the necessity of retaining communications to external agencies when internal response centres are set up during EPRP activations, as mandated by Standard 11. **Status: Closed**
24-14 Security Incident and Crisis Management (ARC 2024 Q4)	[redacted]		

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
[redacted]			
24-15 Darlington New Nuclear Project ("DNNP") – Business Case and Release Quality Estimate (Class 3) (ARC 2024 Q4)	Generally Effective (White)	Some standard procurement milestones were not entered in the P6 schedule, and it is unclear whether equipment will meet the Required-on-Site ("ROS") dates due to procurement log inconsistencies, and not all equipment procurement had a category strategy.	Management will: • Review and update the standard procurement milestones in P6 and procurement log to ensure they are fit for purpose, and where applicable, incorporate these milestones into P6 and procurement log with realistic timelines. Dates in the procurement log will be clearly marked to distinguish between forecast and actual dates; and • Explore options to automatically update P6 milestones with those documented in the Procurement log. • Formally define and document the criteria for requiring category strategies within the SPA Gated Process, including separate preparation of the strategy and procurement plan before submitting the Gate A SPA Form. Additionally, consult with OPG Category Management to ensure visibility and input on these strategies; • Ensure NOPs document relevant Procurement Policies and Procedures in their Subcontractor Management Plans, including any missing project-specific information; and • Assess and update the Master SMP to reflect the current reporting and communication channels, replacing any references to "ad hoc" reporting. **Status: In-Progress**

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Certain missed tier 1 and 2 engineering and procurement milestones lacked formal recovery plans, and in some instances the re-baselined milestone dates have not been achieved.	Management will work with the Project Integration Team (“PIT”) to: • Review the missed and at-risk tier milestones, including their cause and impact on successor milestones. Assess the effectiveness of current recovery activities and implement changes as needed. • Review and update the current project guidance on milestone management and issue management to ensure alignment in handling delayed milestones and review the status of recovery plans for at risk and missed milestones during Execution meetings. **Status: In-Progress**
		Certain risk management activities were not conducted in accordance with established governance and guidelines.	Management will: • Conduct risk QRA input workshops led by Risk Specialists for all the remaining bundle/projects as part of the RQE process. • Conduct refresher training sessions with bundle risk SMEs to highlight the requirements of the Risk Contingency Input Template Guide prior to QRA runs. • Update automated monthly reporting to include “request to activate" risks. **Status: Closed**
			Management will: • Revise the Project Controls Plan to require that monthly reporting of risks in “draft” status that are over 60 days old and “request to activate” status is conducted. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
24-16 Darlington Nuclear Refurbishment ("DNR") Cost and Budget Management (ARC 2024 Q1)	Effective (Green)	Supporting documentation for Change Control Forms ("CCFs") did not consistently follow procedural governance requirements.	Management will: • Define and clarify the process and documentation requirements for approving CCFs above $10 million in the DNR PMP, and will communicate the update to DNR Project Teams and other key stakeholders; and • Perform a risk assessment and identify the CCFs in scope to perform an extent-of-condition review for missing supporting documentation, and close identified gaps as needed. **Status: Closed**
			Management will upload the missing supporting evidence from IA's test results into the required system. **Status: Closed**
24-18 Partnership Compliance Agreement (ARC 2024 Q4)	Effective (Green)	Partnership Agreement obligations were not consistently listed in the Nanticoke Solar Limited Partnership ("NSLP") PMP.	Management will: • Add the omitted obligations to the NSLP PMP during the Q4-2024 update; • Review the key agreements for the Lower Mattagami, Lac Seul, and Peter Sutherland Sr. partnerships to identify obligations that may have been missed in the respective PMPs, and revise the PMPs as part of the Q4-2024 update; and • Revise the NSLP LPA at the next amendment opportunity to remove Article 18.2. **Status: Closed**
		Audited financial statements were not distributed to Partners according to the timeframe stipulated in the NSLP Limited Partnership Agreement ("LPA").	Management will document in an internal memo the approach when OPG is unable to deliver financial statements within 120 days. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
24-23 Board of Directors' Business Expenses (ARC 2024 Q1)	Effective (Green)	Some sampled expenses were not approved in accordance with the authority levels prescribed in OPG's Standard.	Management will revise the Standard for the review and approval of the Board Chair's expenses to be solely completed by the CFO. **Status: Closed**
			Management will obtain the Chair of the ARC's approval for the Board Chair's expenses until the revision of the Standard is made effective. **Status: Closed**
		OPG's Standard was silent on the treatment of certain expenses that had prescriptive requirements within the Directive.	Management will update the Standard to align with the Directive, as follows: • Include additional guidance over security assessments and insurance coverage (i.e., medical, health, and travel accident insurance) for Board members when travelling outside of Canada; and • Include a provision on the treatment of penalties incurred for hotel cancellations. **Status: Closed**
24-25 Environmental Management System Audit Program (ARC 2024 Q1)	Effective (Green)	Documentation was not available to support audit plan approval by EH&S Management.	Management will update OPG-PROC-0044 to clarify documentation requirements for audit plan approvals and required documentation to support delegations of authority. **Status: Closed**
25-01a Bruce Power Ring Fence (ARC 2025 Q1)	Generally Effective (White)	The Energy Markets Compliance Contact ("EMCC") did not provide the list of employees who completed a required training course to the Ring-Fence Coordinator to facilitate oversight, and one employee did not complete the required training.	Management will work with the TIMS system administrators to develop customized automated reports for training monitoring and compliance reporting. **Status: Closed**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		The Ring-Fence governance has not been updated to reflect current practices, controls, and system configurations.	Management has initiated Document Change Request (“DCR”) 170043 to update the Ring-fence procedure to align with current system configurations, practices, and controls. **Status: Closed**
25-01b Atura Power Ring Fence (ARC 2025 Q1)	Generally Effective (White)	The Energy Markets Compliance Contact (“EMCC”) did not provide the list of employees who completed a required training course to the Ring-Fence Coordinator to facilitate oversight, and one employee did not complete the required training.	Management will work with the TIMS system administrators to develop customized automated reports for training monitoring and compliance reporting. **Status: Closed**
		The Ring-Fence governance has not been updated to reflect current practices, controls, and system configurations.	Management has initiated Document Change Request (“DCR”) 170043 to update the Ring-fence procedure to align with current system configurations, practices, and controls. **Status: Closed**
			Management will revise QUAL 44913 information in TIMS to include all the training courses required for EM staff. **Status: Closed**
25-09 Pension and Benefits Administration (ARC 2025 Q2)	Requires Improvement (Yellow)	A pension entitlement audit has not been performed since it was first conducted in 2019, increasing the risk of pension payments to deceased pensioners. Documentation is not	Management will review the identified overpayment cases and initiate recovery actions. **Status: In Progress**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		required to support changes to pensioners' banking records or the enrolment of spouses and dependents for benefits, including any subsequent changes.	Management will: • Issue letters to pensioners over 90 years of age as soon as practically possible using TELUS Health, the existing service provider, and conduct the alive and well audit on this subset of the population; • Initiate a process to secure a vendor to perform "alive and well" audits; and • Define an appropriate interval for the conduct of future alive and well audits through this vendor which is understood to be annual based on vendor proposals and management preference. **Status: In Progress**
		Complementary User Entity Controls ("CUECs") required by vendors engaged by OPG to administer pension and benefits coverages have not been fully assessed for applicability, relevance and effective implementation. Control deficiencies identified in vendor SOC 1 reports were dispositioned without documented rationale.	Management will: • Update the existing P&B process document on the review of SOC 1 reports to: - Include the requirement to review CUECs; and - Require documentation of criteria used and rationale to support disposition of SO control deficiencies identified in the SOC 1 report; • Assess CUECs for applicability to OPG, map applicable CUECs against existing controls, identify owners for control execution and obtain acknowledgment to confirm responsibility acceptance for controls execution; • Review effectiveness of CUECs with relevant stakeholders (frequency to be defined in mapping document) to address any gaps where applicable and retain documentation as evidence of these reviews including any resulting actions; and • Use the updated process document in the review of the 2025 SOC 1 reports. **Status: In Progress**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Some P&B Standard Operating Procedures ("SOPs") are not current and do not address all processes.	Management will: • Refine and update the P&B program SOPs as part of the 2025 department performance objectives; • Expand the 2024 P&B process review initiatives to assess the need to adopt document change control for SOPs in accordance with OPG governance framework; and • Provide the updated P&B program SOPs to relevant HR stakeholders. **Status: In Progress**
25-13 Dam Safety Program (ARC 2025 Q2)	Generally Effective (White)	Not all staff identified by Operations Groups to fulfill emergency management roles have been assigned the training in the Training Information Management System ("TIMS") as required by governance, and the requalification period for one of these trainings was misconfigured in TIMS.	Management will work with RG Training to ensure all employees identified to fill emergency management roles have been assigned the appropriate QUALs and PELs in TIMS as required by governance. **Status: In Progress**
			Management will ensure TIMS is updated to have a requalification period of 60 months for PEL 76287. **Status: Closed**
		Site inspection reports did not include all information and cover all elements required by the Quebec Dam Safety Regulation.	Management will refresh site inspectors' knowledge of the requirements of Section 42.1 of the Quebec Dam Safety Regulation as they relate to the completion of site inspection reports. **Status: In Progress**
		DSRs were not performed at the intervals prescribed by governance, and the review of governance documents was not completed within the required timelines.	Management will complete the execution of plans to ensure that all dams will be within their defined review cycles by the end of the year. **Status: In Progress**
			Management will complete the planned 2025 governance revisions. **Status: In Progress**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
25-16 Fleet Performance (ARC 2025 Q1)	Generally Effective (White)	Letters of Concern ("LOCs") opened for over three months were not raised to Elevation status.	Management will: • Address the overdue LOCs, via LOC closure or progressing the LOC to CFAM elevation as appropriate; and • Document the rationale for LOCs that are open longer than the time established by governance. **Status: Closed**
		Five guidelines and one standard containing performance indicators and associated definitions are overdue for review.	Management will: • Review the six governance documents that are overdue for review; and • Determine the appropriate review frequency for performance indicators and associated definitions and update governance accordingly. **Status: In Progress**
25-19 Nuclear Oversight (ARC 2025 Q1)	Effective (Green)	Responses to elevation and escalation notices issued by Nuclear Oversight were not received within the prescribed timeframes.	Management will remind responsible personnel of the importance of adhering to prescribed timelines regarding responses to elevation and escalation notices. **Status: In Progress**
			Management will review the Nuclear Oversight Elevation and Escalation Procedure (N-PROC-RA-0129) and assess reasonableness of the prescribed timelines for line management responses to elevation and escalation notices, and provide more clarity on steps needed to close escalation notices (i.e. escalation exit). **Status: In Progress**
25-23 Small Hydroelectric Development (ARC 2025 Q2)	Generally Effective (White)	A Commissioning Execution Plan ("CEP") has not been developed for the Coniston/Stinson Redevelopment Project.	Management will develop and formalize the CEP. **Status: In Progress**

Summaries of Internal Audits Completed Since Q4 2020

Audit Title	Report Rating	Finding	Management Action Plans ("MAPs")
		Four overdue actions and one missed milestone were noted for the Coniston/Stinson Redevelopment Project.	Management will review the governance around action and milestone tracking in ePMX at a meeting with the project team members to ensure action notifications are kept up to date. **Status: Closed**
		Schedule Performance Index (“SPI”) figures for sampled monthly project reports are inconsistent between ePMX and the scheduling system.	Management will work with the Digital Project office to ensure that clarification is added to the ePMX tool to highlight the timeframe on which the SPI calculations are performed. **Status: Closed**
		A project design guide was not finalized and issued in a timely manner.	Management finalized and formally issued the Project Design Management Guide on May 23, 2025. **Status: Closed**
25-26 Board of Directors’ 2024 Business Expenses (ARC 2025 Q1)	Effective (Green)	Justification for the reimbursement of a car rental refueling surcharge was not documented in the business expense claim as required by the Standard.	Management will refresh administrative staff’s knowledge of the Standard and reinforce the requirement to document the justification for reimbursement of car rental refueling surcharges. **Status: Closed**
		Three instances of Board-related expenses were not included in the ICO reporting.	Management will include the hotel no-show charge for the Board Member in the Q4 2024 submission to ICO. **Status: Closed**
			Management will refresh administrative staff’s knowledge of the Standard and reinforce the requirements related to the ICO reporting. **Status: Closed**

OVERVIEW OF REGULATED HYDROELECTRIC FACILITIES

1.0 PURPOSE

This evidence describes the regulated hydroelectric facilities. It also identifies the regulations, agreements, and programs key to these facilities.

2.0 DESCRIPTION OF REGULATED HYDROELECTRIC FACILITIES

A total of 54 OPG hydroelectric generating facilities are subject to OEB regulation, representing an installed capacity of approximately 6,566 MW.[1] These facilities are operated and maintained by three regions within OPG's Renewable Generation ("RG") organization: Eastern, Western, and Niagara. Attachment 1 provides an overview of the regional breakdown of OPG's regulated hydroelectric facilities.

Hydroelectric facilities typically include: generating equipment (e.g., turbine assembly, generator, governor, excitation, transformers, protections and controls), related civil works (e.g., powerhouses, dams, headworks, spillways, water conveyance canals, diversion tunnels), and are supported by the facilities required to operate and maintain the generating stations (e.g., control centres, work centres,[2] and headquarters). An overview of the standard systems and components of a hydroelectric facility and typical hydroelectric dam and water conveyance structures is provided in Attachment 2.

Chart 1 presents information on OPG's Regions and regulated hydroelectric generating stations ("GS").

[1] Installed capacity values provided in this exhibit are as of the date of filing and do not reflect any incremental changes to installed capacity expected to result from the projects contemplated in the capital project forecast as described in Ex. D1-1-1.

[2] A work centre may be physically located at a generating station or at a standalone location.

Chart 1 - Regulated Hydroelectric Facilities General Information

Region	Generating Station	In-Service Year	Number of Units In-Service	Net In-Service Installed Capacity (MW)
Eastern	Abitibi Canyon	1933	5	344.8
	Arnprior	1976	2	81.6
	Barrett Chute	1942	4	176.1
	Bingham Chute	1923	2	1.0
	Calabogie	2023[3]	2	10.7
	Chats Falls[4]	1931	4	96.0
	Chenaux	1950	8	143.7
	Chute[5]	1923	2	2.9
	Coniston	1905	2[6]	2.7
	Crystal Falls	1921	4	8.4
	Des Joachims	1950	8	428.8
	Elliott Chute	1929	1	1.6
	Lower Notch	1971	2	274.2
	Matabitchuan	1910	4	9.6
	McVittie	1912	2	2.8
	Mountain Chute	1967	2	170.2
	Nipissing	1909	0[7]	0
	Otter Rapids	1961	4	182.4
	Otto Holden	1952	8	242.8
	R.H. Saunders	1958	16	1,045.0
	Stewartville	1948	5	182.1
	Stinson	1925	2	5.4
Western	Aguasabon	1948	2	47.1
	Alexander	1930	5	68.9
	Auburn	1911	3	1.9
	Big Chute[8]	1993	1	10.0
	Big Eddy	1941	2	8.0
	Cameron Falls	1920	7	91.6
	Caribou Falls	1958	3	91.3

[3] Calabogie GS was originally placed in service in 1917 and was redeveloped in 2023.
[4] Total station installed capacity is 192 MW; OPG is entitled to 50% of the capacity (96 MW) – see Section 2.1.
[5] Formerly Indian Chute GS.
[6] Coniston GS is currently in redevelopment and will have two units in service following project completion.
[7] Nipissing GS has no units currently in service.
[8] Big Chute GS was originally placed in service in 1909, then subsequently redeveloped and placed in service in 1993.

Region	Generating Station	In-Service Year	Number of Units In-Service	Net In-Service Installed Capacity (MW)
	Eugenia	1915	3	6.1
	Frankford	1913	4	2.6
	Hagues Reach	1925	3	3.6
	Hanna Chute	1926	1	1.4
	High Falls	1920	3	2.7
	Kakabeka Falls	1906	4	24.6
	Lakefield	1928	1	1.8
	Manitou Falls	1956	5	73.1
	Merrickville	1915	2	1.7
	Meyersburg	1924	3	5.2
	Pine Portage	1950	4	145.9
	Ragged Rapids	1938	2	8.3
	Ranney Falls	1922	3	19.5
	Seymour	1909	5	5.7
	Sidney	1911	4	4.4
	Sills Island	1900	2	1.8
	Silver Falls	1959	1	52.4
	South Falls	1907	3	5.9
	Trethewey Falls	1929	1	1.8
	Whitedog Falls	1958	3	67.8
Niagara	DeCew Falls 1	1898	4	22.8
	DeCew Falls 2	1943	2	144.0
	Sir Adam Beck 1	1922	10	557.9
	Sir Adam Beck 2	1954	16	1,499.2
	Sir Adam Beck PGS	1957	6	174.0

2.1 Eastern Region

The Eastern Region was created through the organizational realignment implemented across OPG in 2020. The Eastern Region combines the 22 regulated hydroelectric facilities on the Abitibi, Madawaska, Matabitchuan, Montreal, Ottawa, South, St. Lawrence, Sturgeon, and Wanapitei river systems.

The R.H. Saunders GS is a 16-unit hydroelectric station on the St. Lawrence River in Cornwall, Ontario. The R.H. Saunders GS is connected to the 16-unit St. Lawrence - Franklin D. Roosevelt Power Project, which is owned and operated by New York Power Authority ("NYPA"). Together, the two generating stations span the St. Lawrence River. Associated facility structures include: the powerhouse, dams, headworks, dykes, bridges, and ice booms. Under the Memorandum of Understanding between OPG and NYPA, both parties equally share the costs associated with joint works at the St. Lawrence facilities (including the Iroquois Control Dam and Long Sault Dam, headworks, dykes, and the Barnhart Island bridge). The R.H. Saunders GS is maintained and controlled from a work centre and control centre located at the R.H. Saunders GS.

There are four generating stations on the Ottawa River (Otto Holden GS, Des Joachims GS, Chenaux GS, and Chats Falls GS) and five on the Madawaska River (Mountain Chute GS, Barrett Chute GS, Calabogie GS, Stewartville GS, and Arnprior GS). The nine regulated stations on the Ottawa and Madawaska river systems are maintained by six work centres and are remotely controlled from a control centre located at the R.H. Saunders GS.

The eight units and joint works (dams, sluices, and bridges) associated with the Chats Falls GS on the Ottawa River are jointly owned with Hydro-Québec. Four generating units are owned by OPG, and four are owned by Hydro-Québec, with output shared between the two organizations in accordance with the *Ontario Energy Board Act*.[9] OPG operates and maintains the entire station through an Operating Service agreement with Hydro-Québec which was renewed in 2019 and amended in 2025 to contemplate the Chats Falls Expansion project (see Ex. F1-1-1, Section 3.2.6).

There are 12 other regulated hydroelectric facilities in the Eastern Region: three on the South River (Elliott Chute GS, Bingham Chute GS, and Nipissing GS); three on the Wanapitei River (Stinson GS, Coniston GS, and McVittie GS); two on the Abitibi River (Abitibi Canyon GS and Otter Rapids GS); two on the Montreal River (Chute GS and Lower Notch GS); one on the

[9] Ontario Regulation 53/05: *Payments Under Section 78.1 of the Act*, s. 6(2)13(ii), made under the *Ontario Energy Board Act, 1998.*

Matabitchuan River (Matabitchuan GS); and one on the Sturgeon River (Crystal Falls GS). These facilities are maintained by four work centres and are remotely controlled from a control centre located in Timmins.

2.2 Western Region

The Western Region was created through the organizational realignment implemented across OPG in 2021.[10] The Western Region combines the 27 regulated hydroelectric facilities on the Aguasabon, Beaver, English, Kaministiquia, Mississippi, Muskoka, Nipigon, Rideau, Severn, Trent, and Winnipeg river systems.

The Western Region operates nine regulated hydroelectric facilities in northern Ontario: three on the Nipigon River (Pine Portage GS, Cameron Falls GS, and Alexander GS); two on the English River (Manitou Falls GS and Caribou Falls GS); two on the Kaministiquia River (Silver Falls GS and Kakabeka Falls GS); one on the Aguasabon River (Aguasabon GS); and one on the Winnipeg River (Whitedog Falls GS). These generating stations are maintained from three work centres and are remotely controlled from a control centre located in Thunder Bay.

The Western Region also operates 18 regulated hydroelectric facilities in southern Ontario: five on the Muskoka River (Ragged Rapids GS, Big Eddy GS, South Falls GS, Trethewey Falls GS and Hanna Chute GS), one on the Beaver River (Eugenia GS), one on the Severn River (Big Chute GS), seven on the Trent River (Ranney Falls GS, Meyersburg GS, Sidney GS, Hagues Reach GS, Seymour GS, Frankford GS and Sills Island GS), two on the Otonabee River (Auburn GS and Lakefield GS), one on the Mississippi River (High Falls GS) and one on the Rideau River (Merrickville GS). These generating stations are maintained from two work centres and are remotely controlled from the control centre at the Sir Adam Beck complex.

[10] In 2020, the RG organization was realigned into two operating regions, Eastern and Western Region, with the Sir Adam Beck and DeCew Falls facilities included in the Western Region. In 2021, the Niagara Region was formed that included the Sir Adam Beck and DeCew Falls facilities, leaving the Western Region with 27 regulated hydroelectric facilities.

2.3 Niagara Region

The Niagara area regulated facilities include three Sir Adam Beck facilities and two DeCew Falls facilities. The Sir Adam Beck facilities include Sir Adam Beck 1 GS, Sir Adam Beck 2 GS, Sir Adam Beck Pump Generating Station ("PGS") and associated structures such as tunnels, the open cut canal and the International Niagara Control Works ("INCW") structure (also known as International Control Dam), as well as the PGS reservoir. Water conveyance structures (i.e., tunnels and canals) divert water from the upper Niagara River to the Sir Adam Beck generating stations. Water is discharged from the generating stations into the lower Niagara River. Under a Memorandum of Understanding, OPG and NYPA equally share the costs associated with joint works at Niagara, including the INCW.

The DeCew Falls facilities include DeCew Falls 1 GS, DeCew Falls 2 GS and associated water conveyance structures such as Intakes 1 and 2, and the Waterworks canal. Water conveyance structures divert water from the Welland Canal, through Lake Gibson and Lake Moodie, to the DeCew generating stations. Water discharged from the generating stations flows through Twelve Mile Creek to Lake Ontario.

The Niagara area generating stations are controlled from a control centre located at the Sir Adam Beck complex and are maintained from three work centres. The INCW has its own control centre and is maintained by a work centre.

3.0 KEY HYDROELECTRIC REGULATIONS, AGREEMENTS, AND PROGRAMS

OPG's regulated hydroelectric facilities are subject to international treaties between Canada and the United States, federal and provincial legislation and regulatory requirements, as well as several contractual arrangements with third parties. Collectively these regulations, agreements and programs result in additional costs and program needs with respect to the operation and management of the regulated hydroelectric facilities.

This section provides an overview of:

- Regulations, treaties and agreements with regard to water rights for the regulated hydroelectric facilities;

- Agreements with other utilities and generators related to operational requirements, guidelines, joint works, water sharing, water diversions, and compensation settlements;
- Dam and public safety governance and programs; and
- Indigenous Relations.

A summary of the legislative and regulatory framework applicable to OPG's regulated facilities is provided at Ex. A1-6-1. Additionally, details on the gross revenue charge payable to the Province of Ontario, and water rental charges and other water agreement costs payable to other governments, agencies, or companies, are provided in Ex. F1-4-1.

3.1 Water Rights

3.1.1 Regulation of Water Rights

Rights to and restrictions on the use of water are determined by international treaties between Canada and the United States, together with the application of interprovincial agreements, federal and provincial legislation, common law as it pertains to real property and riparian rights, as well as the terms and conditions of certain leases and permits with and from the Government of Canada and the Province of Ontario. Water management plans authorized by the Ontario Ministry of Natural Resources ("MNR") prescribe water elevation and flow limits for many of Ontario's major rivers.

3.1.2 International Boundary Waters

Through a series of agreements between the Government of Canada and the Province of Ontario, OPG has been granted the right to exercise Canada's rights with respect to the construction, maintenance, and operation of hydroelectric generating facilities on the Niagara and St. Lawrence Rivers under the *Boundary Waters Treaty of 1909*, the *Niagara Diversion Treaty of 1950*, the *Niagara Development Act of 1951*, and the *International Rapids Power Development Agreement Act of 1952*.

The *Boundary Waters Treaty of 1909* governs all boundary waters between Canada and the United States. Water rights on both the Niagara and St. Lawrence Rivers are subject to this treaty. The Treaty created the International Joint Commission ("IJC") to help prevent and

resolve disputes over the use of boundary waters between Canada and the United States. The IJC established the International Niagara Board of Control to oversee water level regulation on the Niagara River, and the International Lake Ontario-St. Lawrence River Board ("ILO-SLRB") to ensure Lake Ontario outflows meet IJC requirements, including dependable flow for hydropower and adequate depths for navigation on the St. Lawrence River.

Since 1956, Lake Ontario and the St. Lawrence River were managed following an IJC order of approval termed Plan 1958-D with deviations from the plan allowed. Scientific studies revealed this plan contributed to several negative ecosystem impacts and as a result a new plan was introduced. Plan 2014 was recommended for use by the IJC's Great Lakes Adaptive Management Committee and International St. Lawrence River Board of Control ("ISLRBC"). An IJC Order of Approval was issued in December 2016 creating the ILO-SLRB as a successor to the ISLRBC and officially adopting Plan 2014 for use starting in 2017, after 14 years of scientific study and public consultation.

The *Niagara Diversion Treaty of 1950* between Canada and the United States, among other things, determines the priority of use for the waters flowing out of Lake Erie (Niagara River and Welland Canal), sets minimum flow requirements over Niagara Falls, and provides for the allotment of the waters available for power generation. It also recognizes that certain diversion waters are to be excluded from determination of the water allotment.

The International Niagara Committee ("INC") was created by the Governments of Canada and the United States pursuant to the *Niagara Diversion Treaty of 1950* to determine and report the amounts of water available for purposes of the Treaty, including water used for power diversions at Niagara. The INC is independent of the IJC, but works in collaboration with the IJC's International Niagara Board of Control.

The *Niagara Parks Act* (Ontario) provides the Niagara Parks Commission with the authority to grant certain rights to use the waters of the Niagara River for purposes of power generation. By agreement executed in 2005, the Niagara Parks Commission has granted OPG sole rights

to take water from the Niagara and Welland Rivers for purposes of power generation until December 31, 2056.

The DeCew Falls generating stations use water that is conveyed through the Welland Canal from Lake Erie under an agreement between OPG and the St. Lawrence Seaway Management Corporation that expires June 30, 2038, with rates subject to renewal every five years (see Ex. F1-4-1, Section 4.0).

3.1.3 Interprovincial Rivers

Four of OPG's regulated hydroelectric generating stations are located on the Ottawa River which forms the provincial boundary between Ontario and Québec. The *Ottawa River Water Powers Act, 1943*, (concurrent legislation, Ontario and Québec) authorized the water power developments at Otto Holden GS, Des Joachims GS, and Chenaux GS on the Ottawa River. The fourth station, Chats Falls GS, is owned jointly by OPG and Hydro-Québec (Section 2.1). The four generating stations are subject to water power lease agreements with the MNR. A renegotiation of the *Agreement Regarding the Review of the Rent for the Water Powers of the Ottawa River*, which sets the Province of Québec water rental rates for the *Ottawa River Water Powers Act*, was completed on November 26, 2020. The updated agreement held the 2020 water rental rate constant until 2023 after which it rises annually with inflation.

An Agreement Respecting Ottawa River Basin Regulation, dated March 2, 1983, between the Governments of Canada, Ontario, and Québec, established the Ottawa River Regulation Planning Board and Secretariat to oversee the integrated management of the waters within the Ottawa River basin. OPG participates as a member of the Board.

Whitedog Falls GS is located on the Winnipeg River which flows from the Lake of the Woods in northwestern Ontario to Lake Winnipeg in Manitoba. Manitou Falls GS and Caribou Falls GS are located on the English River which is a major tributary to the Winnipeg River just east of the Manitoba-Ontario provincial border. These three generating stations are subject to water power lease agreements with the MNR.

Concurrent federal and provincial (Ontario and Manitoba) legislation authorizes regulation of the waters of the Lake of the Woods, Lac Seul, the English and Winnipeg Rivers, control of flows, and utilization of water diverted from the Lake St. Joseph. The Lake of the Woods Control Board is the regulating authority for managing these waters.

3.1.4 Provincial Rivers

Forty-one of OPG's regulated hydroelectric generating stations are located on 17 interior Ontario rivers. Tenure at 31 of these sites is authorized by water power lease agreements with the MNR, or licence agreements with Parks Canada. The remaining 10 of these sites are owned by OPG.

In addition, OPG holds eight Crown Leases and 27 Licences of Occupation, issued by MNR, that provide additional land tenure and flooding rights for facilities associated with the regulated hydroelectric generating stations.

Water Management plans, authorized by the MNR, exist for 14 of the 17 interior rivers and prescribe flow and water level elevation limits. The other three rivers (Rideau, Trent, and Severn) fall under federal jurisdiction and are not subject to Ontario Water Management Plans.

3.2 Agreements with Other Utilities

OPG also has agreements with NYPA, Hydro-Québec, and Manitoba Hydro to address issues such as operational requirements/guidelines, cost sharing and management of joint works, water utilization, and settlement of water/energy transactions.

3.3 Dam Safety and Waterways Public Safety

3.3.1 Dam Safety

There are 192 dams and special hydraulic structures associated with OPG's regulated hydroelectric stations.

In Canada, dams come under provincial jurisdiction, with the exception of dams situated in boundary waters, on canals (e.g., the Trent Severn Waterway and the Rideau Canal), and those owned by the Government of Canada. The majority of OPG's dams fall within the jurisdiction of the Province of Ontario. The structures on the Ottawa River are also regulated by the Province of Québec. OPG provides regular submissions to the Province of Québec to demonstrate that these structures remain in compliance with the *Québec Dam Safety Act and Dam Safety Regulation*.

For dams located on the Trent Severn Waterway and the Rideau Canal system, OPG is required to meet Parks Canada dam safety criteria (2010 Directive), primarily as it applies to upgrading structures.

The Province of Ontario currently governs dams under the *Lakes and Rivers Improvement Act* ("LRIA"), administered by the MNR. In June 2019, OPG entered into an Agreement with MNR that allows OPG to undertake repairs and alterations to OPG dams under OPG's Dam Safety Program oversight and provides relief from obtaining LRIA Section 16 approval. The Agreement with MNR requires that OPG have a robust dam safety program (i.e., a managed system) and maintain a good LRIA compliance record.

Transport Canada also has regulatory approval authority over OPG dams under the *Canadian Navigable Waters Act* as they may relate to alterations to the dams or approved works (e.g., safety booms, cofferdams, boat launches, etc.).

While the regulatory regime in Ontario continues to develop, OPG has well-established programs based on the *Canadian Dam Association Dam Safety Guidelines* (2013) and the *Canadian Dam Association Guidelines for Public Safety Around Dams* (2011), as well as other industry guidelines that are, in many respects, a model for emerging standards and regulatory requirements. OPG's Safe Operations Policy and the associated Dam Safety Program Management Document directs that dams comply with all applicable legislation and take into consideration best practices as recommended in guidelines published by the Canadian Dam Association, or other appropriate national and international risk management practices.

The OPG Dam Safety Program represents a comprehensive framework, intended to integrate the processes, practices, people and resources to achieve the overall objective to manage risk and ensure safe and responsible management of OPG's dams. Within the program, Performance Monitoring is a key component that provides assurance that the dams continue to be operated and maintained in a safe manner. Routine dam safety activities include activities such as, inspection, surveillance, instrumentation and monitoring, testing, and incident reporting.

3.3.2 Waterways Public Safety

Currently there are no regulations covering public safety around dams, beyond the federal requirements administered by Transport Canada under the *Canadian Navigable Waters Act* (2019) or *Canada Shipping Act* (2001) and the associated regulations. Transport Canada's involvement in public safety is primarily related to the installation of safety measures (e.g., safety booms, buoys) and enforcement of restrictions to navigation.

In keeping with OPG's Safe Operations Policy, OPG's Waterways Public Safety Program aligns with industry best practices as recommended in guidelines, specifically the MNR Best Management Practice *Public Safety for Dam Owners* (August 2011) and the Canadian Dam Association *Guidelines for Public Safety Around Dams* (October 2011). The program includes risk assessments, installation of physical control measures (e.g., booms, buoys, fencing, signage, audible alerts), operating procedures, incident reporting, and employee training requirements. A major element of the program is public education. For example, OPG has worked to establish a "Stay Clear – Stay Safe" message. OPG actively engages other agencies such as the MNR, Ontario Provincial Police, St. John's Ambulance, Life Saving Society, the Ontario Waterpower Association, and numerous other stakeholders in water safety education to partner in delivering the message to the public.

3.4 Indigenous Relations

OPG's hydroelectric assets are widely dispersed throughout Ontario, with many generating stations and dams in close proximity to various Indigenous communities. This proximity to dams and generating stations has had both direct and indirect effects on some Indigenous

communities during initial construction and from ongoing operations. OPG's Indigenous Relations Policy and Reconciliation Action Plan formalize the Company's commitment to working with Indigenous Nations and communities to foster positive and mutually beneficial relationships that will create social and economic benefits through partnership and collaboration.

OPG continues to undertake a number of activities and initiatives to maintain ongoing and collaborative relationships with Indigenous Nations and communities proximate to OPG's hydroelectric assets. This includes proactive and regular engagement with Indigenous Nations and communities with respect to OPG's operations as well as undertaking the procedural aspects of consultation for projects and activities that trigger the Crown's legal duty to consult.

For example, OPG is undertaking a project to redevelop the Kakabeka Falls GS, which involves the construction of a new powerhouse extension, replacement of the surge system, and replacement of the penstocks to ensure continued safe and reliable operations for approximately the next 90 years (Ex. D1-1-2, Section 3.2.2). Through discussions between OPG and the Fort William First Nation, an agreement in principle has been reached whereby OPG would provide compensation to the Fort William First Nation in connection with the project. The compensation is in the form of a redevelopment revenue payment to be made on an annual basis, beginning when the Kakabeka Falls GS is returned to service following redevelopment.[11]

OPG has engaged in a past grievance settlement program since 1992 to address some of the effects on Indigenous communities. The program is voluntary and non-adversarial. A successful outcome of the program is a negotiated settlement acceptable to both parties. To date, OPG (and formerly Ontario Hydro) has completed settlements with 21 First Nation communities across Ontario. This has been key to advancing positive relationships with First Nations.

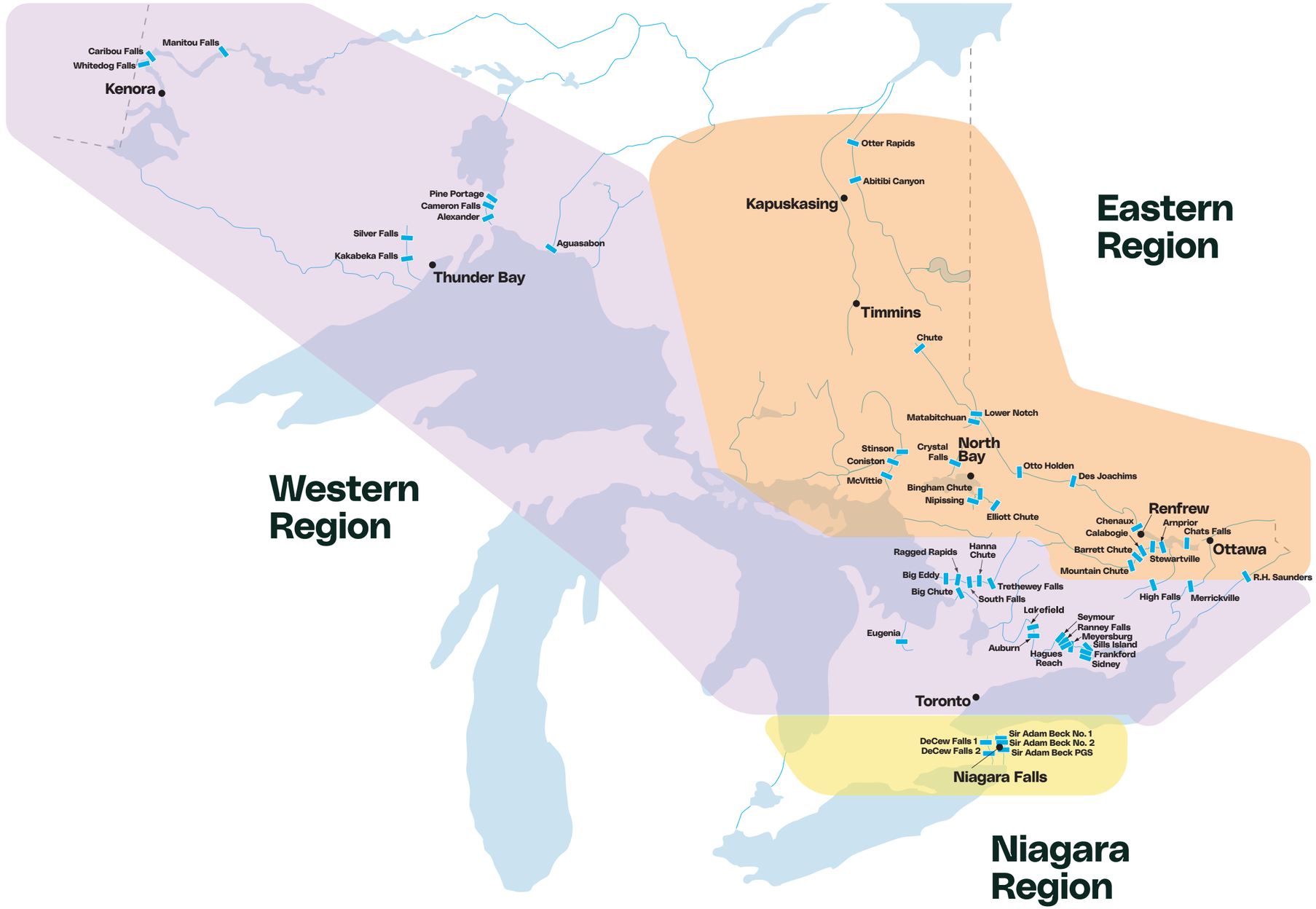
[11] Since the planned in-service for the Kakabeka Falls GS redevelopment is in May 2028 and the proposed hydroelectric rate-setting framework is based on a forecast of 2027 OM&A expenses only, there is no direct cost associated with this redevelopment revenue payment in the revenue requirement proposed in this Application.

LIST OF ATTACHMENTS

Attachment 1: OPG Regulated Hydroelectric Facilities Map

Attachment 2: Hydroelectric Facility Standard Systems

Renewable Generation Fleet Map



Legend

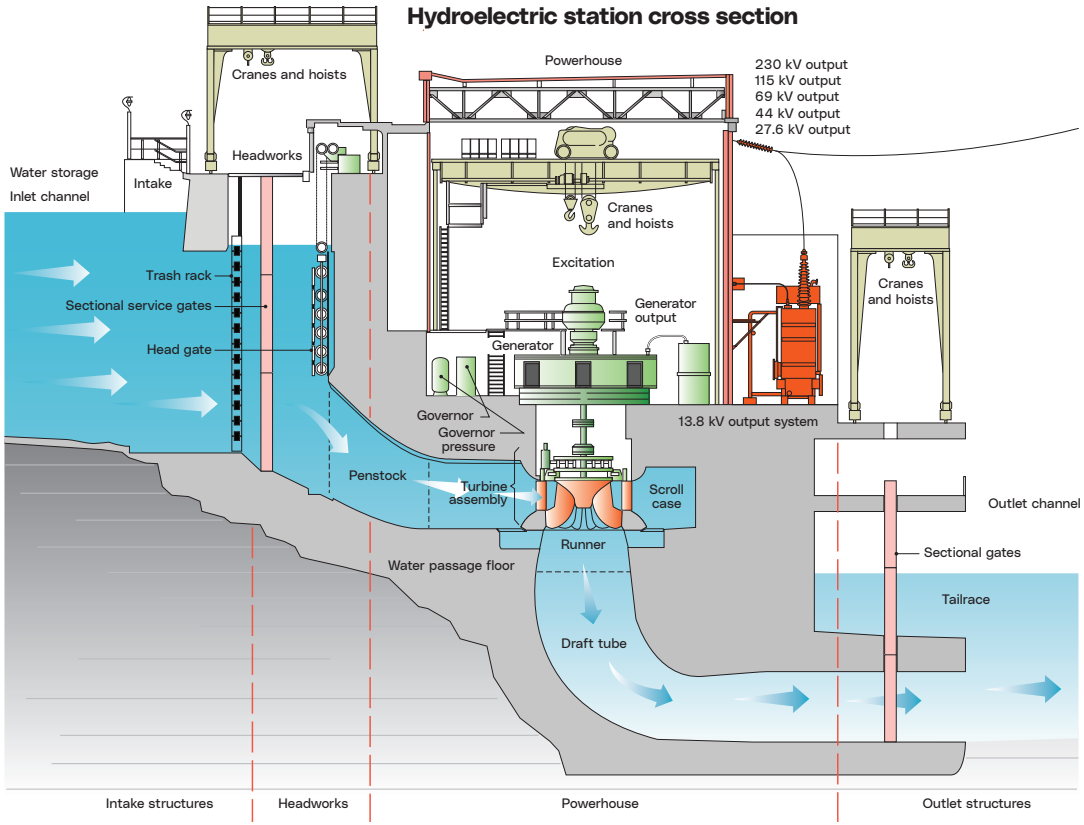
Regulated Hydro Stations

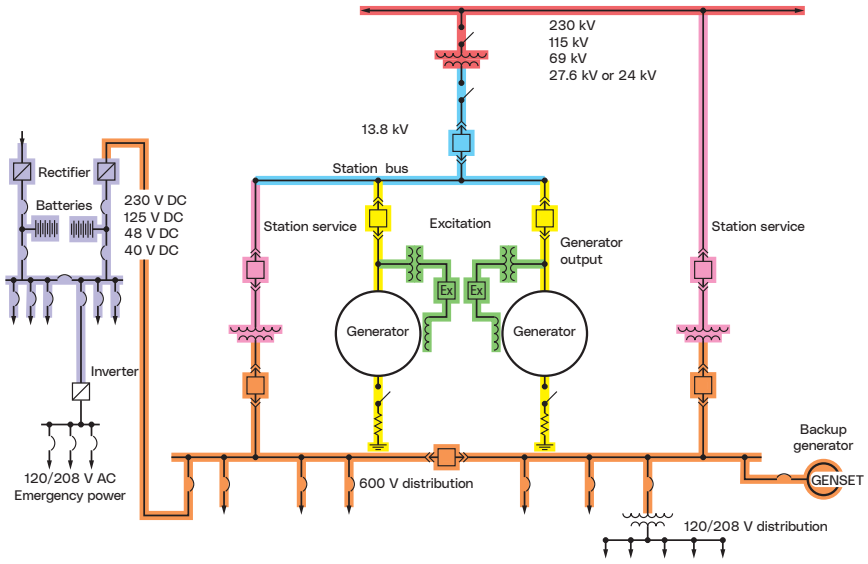
ONTARIO POWER GENERATION

Revision date: April 2025

This map reflects OPG regulated hydro facilities only.

Hydroelectric facility standard systems





This graphic illustrates a typical hydroelectric facility, though sites may vary.

Typical Dam and Water Conveyance Structures

Hydroelectric station site and associated systems



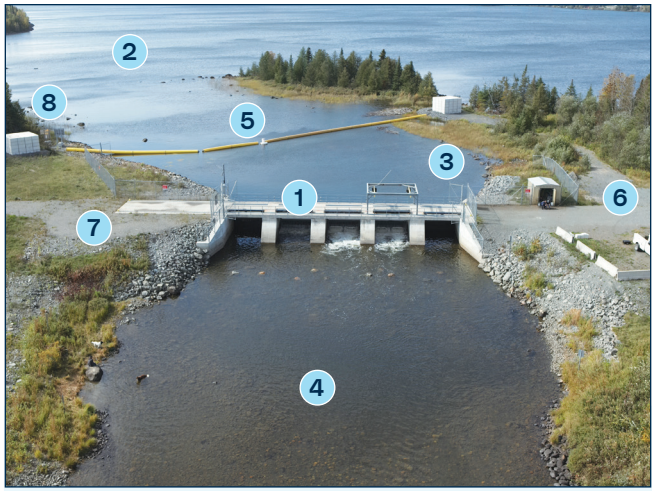
1. Powerhouse
2. Control dam
3. Intake structures/power dam
4. Outlet structures/tailrace
5. Sluiceway, spillway
6. Electric power structures
7. Reservoir
8. Boom
9. Site access
10. Site and yard

Intake and dams



1. Intake power dam
2. Control dam
3. Block dam/retaining structures
4. Sluice Gate
5. Headworks
6. Surge tank
7. Spillway
8. Log machine
9. Reservoir
10. Channel
11. Boom
12. Site access

Control dam



1. Control Dam
2. Reservoir
3. Lifting Frame
4. Channel
5. Boom
6. Site Access
7. Earth Embankment
8. Public Safety Measures

OVERVIEW OF NUCLEAR FACILITIES

1.0 PURPOSE

This evidence describes OPG's nuclear facilities and sets out an overview of OPG's nuclear mandate, objectives, organization, and governance framework.

The evidence is substantially the same as Ex. A1-4-3 submitted in OPG's last payment amounts application (EB-2020-0290) with the exception of the addition of the Darlington New Nuclear Program ("DNNP") in Section 3.0, and an update to Section 4.0, Nuclear Organization and the inclusion of Section 6.0, Indigenous Relations.

2.0 OPG'S EXISTING NUCLEAR GENERATING FACILITIES

OPG's nuclear generating facilities consist of the Pickering Nuclear Generating Station ("Pickering") and the Darlington Nuclear Generating Station ("Darlington") (collectively, the "nuclear generating stations"). OPG is also executing on the DNNP, with its first unit entering commercial operation in 2030.

Pickering and Darlington are based on Canada Deuterium Uranium ("CANDU") technology, a pressurized-heavy-water reactor using natural-uranium technology developed in Canada. CANDU reactors are unique in their use of natural uranium, deuterium oxide (heavy water) as a moderator/coolant, on-line refueling capability and two shutdown safety systems. These plants serve as base load resources as they have been designed to operate at full power. Chart 1 below provides basic information about the nuclear generating stations.

Chart 1 - Nuclear Generating Stations Basic Information

	Pickering		Darlington
	Units 1 and 4[1]	**Units 5-8**	**Units 1-4**
Original In-service dates	1971-1973	1983-1986	1989-1992
Refurbishment return-to-service dates	N/A	2031-2034[2]	2020-2026
Net in-service capacity	1,030 MW	2,064 MW	3,512 MW
Number of units in-service and size in MW's	2 x 540	4 x 540	4 x 934

[1] Pickering Units 2 and 3 were laid up in 1997 and have been placed into a safe store condition for eventual dismantling. Pickering Units 1 and 4 have ceased operations in 2024 and are in the process of lay-up, for safe store and eventual dismantling.
[2] Pickering Units 5-8 projected Return-to-Service dates.

While these nuclear units are based on CANDU principles, they reflect three generations of design philosophy and technology with Pickering Units 1 and 4 (part of "Pickering A"), Pickering Units 5-8 ("Pickering B"), and Darlington built in the 1960s, 1970s, and 1980s respectively. This has resulted in significant variations among the three nuclear stations, including technology, system components, and overall design.

Pickering has completed its safe shutdown sequence of Units 1 and 4, ceasing operations in October 2024 and December 2024, respectively, transitioning into Safe Store operations.[1]

Planning is underway to refurbish Pickering Units 5-8 over the period of 2027-2034, following the end of their pre-refurbishment commercial operations in September 2026. Further details regarding Pickering Units 5-8 Refurbishment are provided in Ex. D2-3-1 and Ex. F2-8-1.

Darlington continues to undergo refurbishment of Unit 4, with Units 2, 3, and 1 successfully returned to service in June 2020, July 2023 and November 2024 respectively, as discussed in Ex. D2-2-1 and Ex. F2-7-1. Unit 4 is expected to return to service by April 2026.

[1] The costs of these activities are charged against OPG's nuclear decommissioning liability.

A summary of the legislative and regulatory framework applicable to OPG's regulated facilities is provided at Ex. A1-6-1.

3.0 DARLINGTON NEW NUCLEAR PROGRAM

DNNP LP is a limited partnership formed under the laws of the Province of Ontario, and DNNP GP Inc. ("DNNP GP") is the managing general partner of DNNP LP with the authority to act on behalf of DNNP LP. DNNP LP will be a newly prescribed generator subject to certain conditions set out in section 8 of O. Reg. 53/05 and is entering into a lease for the DNNP facilities with OPG. DNNP LP will undertake the development, construction, and operation of the DNNP facilities, with OPG contracted to act as the project manager and operator of the facilities. The Application assumes that DNNP LP enters into the lease and associated agreements and that the DNNP asset transfer from OPG all occur at the end of 2025. DNNP LP will not have its own workforce and will contract for all applicable services with OPG, and will therefore reimburse OPG for its fully allocated costs of providing the services.

The DNNP is constructing the first small modular reactor ("SMR") to be situated on the eastern portion of OPG's Darlington site. The SMR is a BWRX-300 boiling water reactor that is comparatively smaller than the Pickering and Darlington CANDU units. DNNP is planned to consist of four SMRs that will have a total output of approximately 1,200 MW, which is enough electricity to reliability and safely power about 1.2 million homes.

OPG has held a Licence to Prepare Site for the Darlington New Nuclear site from the Canadian Nuclear Safety Commission ("CNSC") since 2012. In April 2025, the CNSC issued OPG a Licence to Construct one SMR at the site. The first SMR, together with common scope facilities for all four planned SMRs, is scheduled to be in-service in 2030. OPG plans to submit a CNSC Licence to Operate application for the first SMR in 2026. Construction of additional SMRs is subject to future approvals.

Chart 2 – DNNP Basic Information

	DNNP
Planned In-service Date	October 2030 (Unit 1)
Planned Net In-Service Capacity	315 MW per unit
Planned Number of units in-service and size in MW's	327 MW per unit

Further details regarding the DNNP are provided in Ex. D2-4-1. An overview of the ownership and legislative structures related to the DNNP is provided in Ex. A1-4-4.

4.0 NUCLEAR ORGANIZATION

OPG's electricity generating operations and associated centralized operations support groups form part of a single Enterprise Operations organization. OPG's major project planning, execution and support responsibilities across the company form part under a single Enterprise Projects organization.

As it relates to the nuclear facilities, Enterprise Operations and Enterprise Projects is comprised of the following main groups described below, consistent with OPG's organizational chart shown in Ex. A1-5-1.

Enterprise Operations: led by the Chief Operations Officer and Chief Nuclear Officer and, relative to nuclear operations, comprised of:

- **Darlington and Pickering Stations:** led by the Senior Vice President ("SVP"), Pickering and SVP, Darlington and focused on the operation, maintenance, and performance of Pickering and Darlington.
- **Enterprise Engineering:** led by the Chief Enterprise Engineer and focused on plant safety and reliability by provision of various engineering services (e.g., design engineering, component engineering, station engineering), as well as providing inspection and maintenance services to Darlington and Pickering facilities.
- **Integrated Fleet Management:** led by the SVP, Integrated Fleet Management and, relative to nuclear operations, comprised of:

- **Security & Emergency Services:** while reporting to SVP, Integrated Fleet Management, provides two main functions across the Nuclear fleet consisting of security services for nuclear sites and facilities as well as nuclear training of personnel to safely operate, maintain and improve performance of Pickering and Darlington.
- **Fleet Performance including Stakeholder Relations:** led by the VP, Fleet Performance, drives improvement by developing, implementing and monitoring fleet-wide programs and procedures for the nuclear stations in operations, maintenance, performance improvement and human performance; also responsible for fleet maintenance, fleet work management, radiation safety and generation planning. Stakeholder Relations acts as the primary liaison for external stakeholders including the Institute of Nuclear Power Operations, World Association of Nuclear Operators and Nuclear Safety Review Board, by fostering strong relationships and ensuring site visits to OPG are planned and executed in compliance with regulatory requirements. **Enterprise Learning:** led by the VP, Enterprise Learning, drives corporate and site organizations to achieve, maintain, and improve worker performance. It is key to improving Nuclear station safety, reliability, and cost effectiveness and ensures that workers are trained and qualified to perform the duties of their position and applies to workers engaged in licensed activities.

- **Other Operations Support:**
  - **Nuclear Sustainability Services:** led by the VP, Nuclear Sustainability Services is responsible for the ongoing long-term management of nuclear waste materials produced by OPG's operations, including low and intermediate level irradiated waste and used fuel, and is predominately funded from the nuclear liabilities. Further details on nuclear waste management, including the financial aspects of the nuclear liabilities are provided in Ex. C2-1-1.
  - **Nuclear Oversight:** responsible for managing an independent assessment program that performs a comprehensive evaluation of all activities affecting OPG nuclear facilities for consistency with applicable laws, regulations, regulatory commitments, licences, and other requirements.

- **Nuclear Regulatory Affairs:** accountable for obtaining required CNSC approvals in a timely manner, ensuring compliance with licences, regulatory requirements and commitments, managing regulatory matters and maintaining working relations with the CNSC.
- **Nuclear Sustainability Strategy:** led by the VP, Nuclear Sustainability Strategies, comprised of Nuclear Decommissioning, responsible for evaluating, developing and advancing decommissioning strategies, as well as Nuclear Sustainability Strategy and Community Relations, including OPG's Nuclear Medicine and Radioisotopes program (described in Ex. G2-1-1).

- **Environment and Health & Safety ("EHS"):** led by the VP, EHS, develops and maintains EHS managed systems, programs and initiatives that support all employees in the company. The group provides expertise and operational support to OPG operations, facilities, projects and functions to meet EHS compliance obligations, and to minimize EHS risks and impacts, and advises on management of environmental issues, health and safety hazards, and prevention of workplace injuries in support of a strong safety culture.

Enterprise Projects: led by the Chief Projects Officer are comprised of:[2]

- **Nuclear Projects:** responsible for the planning, developing and execution of all nuclear projects (other than the Darlington Refurbishment Program, the Pickering Refurbishment Program and the DNNP).
- **Enterprise Project Management Office:** responsible for oversight of the processes, tools and project expertise necessary to deliver successful projects; serves as a source for best practices, training programs and an organizational focus for improving project performance across all portfolios. This group is also responsible for commercial relationships to support effective management of contracts during the post award, execution and close out phases, including Nuclear Extended Services Master Services Agreements and Engineering contracts.

[2] Enterprise Projects also includes the Nuclear Refurbishment organization responsible for the planning and execution of the Darlington Refurbishment Program, Pickering Refurbishment Program and Darlington New Nuclear Program.

- A more detailed description of the roles and responsibilities of the various operating groups in the nuclear business is provided in Attachment 1 to Ex. F2-2-1.

5.0 NUCLEAR OBJECTIVES

OPG's nuclear operations have the following cornerstone major focus areas with the purpose of making the existing nuclear facilities more dependable, predictable, and cost effective:

- **Safety:** The Safety cornerstone makes nuclear safety, employee safety and environmental safety (e.g., radiation) the overriding priorities. It requires that all laws and industry/regulatory expectations are met, activities are performed conservatively and responsibly, and that business decisions are made with the full knowledge of the risks and potential impacts.
- **Human Performance/Leadership:** The Human Performance/Leadership cornerstone recognizes that minimizing individual fallibility and organizational programs/processes is the basis for operational excellence.
- **Reliability:** The Reliability cornerstone requires that OPG operate, maintain and engineer the nuclear facilities such that equipment, performance, availability and output are optimized.
- **Value for Money:** The Value for Money cornerstone delivers solutions that are the best combination of cost, quality and performance.

These cornerstone major focus areas are the basis for the establishment of performance targets and key initiatives during the benchmarking and business planning process, as discussed in Ex. F2-1-1.

6.0 INDIGENOUS RELATIONS

As described in Ex. A2-2-1, OPG will continue to build mutually beneficial working relations with Indigenous communities proximate to its current and planned future operations through proactive engagement, consultation, fostering opportunity and other efforts, including through OPG's Indigenous Opportunities Network ("ION"), which completed its seventh year in 2024. The program, a collaboration between OPG, the Electrical Power Systems Construction Association, Kagita Mikam Aboriginal Employment and Training, unions, and vendors engaged

on the Darlington Refurbishment project, places Indigenous participants in energy sector building trades, such as carpenters, boilermakers, and millwrights.

In 2024, OPG initiated a cross-functional process to develop a new ION Strategy to identify areas of success and opportunities for growth, informed by feedback from former program participants, Indigenous communities and stakeholders as well as industry trends. As of December 31, 2024, the ION program exceeded its annual target by 10 percent, with 55 ION participants placed into employment roles. Since the program was launched in 2018, a total of 180 ION participants have been placed into employments roles.

OVERVIEW OF DNNP LP

1.0 PURPOSE AND OVERVIEW

The applicant DNNP LP is an Ontario limited partnership among 1001368516 Ontario Inc. (the initial limited partner), DNNP GP Inc. ("DNNP GP") as managing general partner of DNNP LP, and OPG as general partner. DNNP LP is expected to be a newly prescribed generator[1] and OEB-licence holder for the DNNP facilities. In September 2025, the Canada Growth Fund Inc. ("CGF") and Building Ontario Fund ("BOF") (together, BOF and CGF referred to as the "Government Agencies") entered into an equity commitment agreement, which upon contribution that is subject to satisfaction of certain conditions, will grant the parties minority ownership rights in DNNP LP.

This exhibit provides an overview of DNNP LP business objectives, organizational structure, and applicable rate-setting framework as established in Ontario Regulation 53/05 ("O. Reg. 53/05"), under the *Ontario Energy Board Act, 1998* (the "Act") and serves as a roadmap of approvals sought by DNNP LP in this Application. The DNNP LP's 2026-2031 business plan is included as Attachment 1.

The following information is provided in this exhibit:

- Section 2.0 provides an overview of the DNNP LP organizational structure.
- Section 3.0 describes the regulatory framework applicable to DNNP LP and the DNNP facilities as defined by O. Reg. 53/05, including establishing a blended payment amount for OPG's nuclear facilities and the DNNP facilities.
- Section 4.0 discusses the nature of capital expenditures and OM&A expenses incurred by DNNP LP; and
- Section 5.0 summarizes the DNNP revenue requirement and production forecast proposed in this Application.

[1] Pursuant to s.78.1 of the *Ontario Energy Board Act, 1998* and section 8 of O. Reg. 53/05, DNNP LP is expected to be prescribed subject to an order made by the OEB in which it specifies that certain conditions have been met.

2.0 PARTNERSHIP OVERVIEW

2.1 Agreements

DNNP LP is a limited partnership formed under the laws of the Province of Ontario. The partnership was established to facilitate investment in the DNNP and, through a series of agreements as further described below, will develop, construct, and operate the DNNP facilities.[2] DNNP GP is the managing general partner of DNNP LP with the authority to act on behalf of DNNP LP.

Under equity commitment agreements entered into in September 2025, limited partner units of DNNP LP and shares of DNNP GP Inc. are expected to be held by OPG and the Government Agencies. OPG and the Government Agencies will hold ownership interest across all four units and all common infrastructure of the DNNP facilities, subject to requisite approvals for future units to proceed to construction.

To carry out the purposes of DNNP LP set out above, DNNP LP has entered, or will enter, into a series of agreements with OPG, summarized as follows:

- **Lease Agreement (the "Lease"):** DNNP LP will lease all or part of the lands and premises identified under Schedule 2 of O. Reg. 53/05, on which DNNP LP will undertake the development, construction and operation of the DNNP facilities starting with Unit 1. Under the terms of the Lease, OPG, as landlord, will be responsible for the nuclear waste management and decommissioning obligations arising from the DNNP facilities.
- **Reimbursement Agreement:** OPG will transfer certain assets to DNNP LP, such as tangible personal property, transferrable warranties and guarantees from third parties, and contracts related to the DNNP facilities (the "Asset Transfer"). DNNP LP will reimburse OPG for all construction in progress costs through the issuance of ownership units. OPG will remain the majority owner and, under the terms of the MOMA discussed below, OPG will be the operator of the DNNP facilities. Subject to the satisfaction of certain conditions, each of CGF and BOF will acquire minority interests in the DNNP LP representing up to 15% and 7.5% ownership, respectively.

[2] An overview of the DNNP is provided at Ex. D2-4-1.

- **Project Management Agreement ("PMA"):** From and after the Asset Transfer date, DNNP LP will engage OPG to manage, oversee, and deliver all project management services for the development, design, and construction of the DNNP facilities. DNNP LP will reimburse OPG for its fully allocated costs incurred to construct the DNNP facilities. DNNP LP is not expected to have its own direct employees.
- **Management, Operations, Maintenance and Administration Agreement ("MOMA"):** DNNP LP will retain OPG as the exclusive Operator of the DNNP facilities. The MOMA details the scope of services, authority, and responsibilities of OPG as the Operator, including regulatory compliance, budgeting, reporting, insurance, dispute resolution, confidentiality, and engagement with Indigenous communities. DNNP LP is obligated to reimburse OPG for its fully allocated costs incurred to operate the DNNP facilities. DNNP LP is not expected to have its own direct employees.
- **IESO Payments Collection, Allocation, and Settlement Agreement:** As discussed below, the regulatory framework under section 14(2)7 of O. Reg. 53/05 contemplates a single blended nuclear payment amount established for the DNNP LP and OPG's nuclear facilities. As such, DNNP LP will appoint OPG as payments collection, allocation and settlement agent to collect DNNP LP's portion of revenue payable by the IESO on account of electricity generated by the DNNP facilities and OPG nuclear facilities at the single blended nuclear payment amount.

The Application assumes that DNNP LP enters into the lease and associated agreements and that the DNNP asset transfer from OPG all occur at the end of 2025.

2.2 Licences

As discussed above, DNNP LP and OPG will enter into a MOMA under which OPG will provide operating and maintenance services in respect of the DNNP facilities. Notwithstanding the fact that OPG will provide operating services, DNNP LP will retain discretion for material operating decisions in respect of the DNNP facilities, and will obtain an electricity generation licence in respect of the operation of the DNNP facilities.

3.0 REGULATORY FRAMEWORK

An overview of the legislative and regulatory framework that governs OPG's regulated facilities and the DNNP facilities is provided at Ex. A1-6-1. DNNP LP is expected to be a prescribed generator for the purposes of section 78.1 of the Act, with the key elements of its rate-setting framework set out in O. Reg. 53/05, as discussed below.

In May 2025, the Ministry of Energy and Mines proposed regulatory amendments to enable equity partnerships for the DNNP, stating the following in a posting to the Environmental Registry of Ontario:

> Absent regulatory amendments, if OPG were to establish a new commercial partnership for the Darlington SMRs to allow equity investments from public, private or Indigenous investors, the generating facility would no longer be subject to OEB rate-regulation under the current O. Reg. 53/05 since the new entity or entities would not otherwise be eligible as "prescribed" generators.
>
> As such, amendments to O. Reg. 53/05 are required to prescribe any new partnerships for the project as a rate-regulated generator and set out its applicable rate-setting framework. This would ensure that any SMRs that are built as part of the DNNP remain subject to oversight by the OEB through its public and transparent rate-setting processes.[3]

The proposed amendments received Royal Assent in December 2025. Amendments related to DNNP LP generally appear under Part III of the regulation, which applies subject to the OEB issuing an order specifying satisfaction with certain conditions set out in section 8 of O. Reg. 53/05. The Application expects that these requirements will be met at the end of 2025. The following sections 1-6 are subject to the satisfaction of certain conditions under Section 8 of O. Reg. 53/05, which OPG expects to satisfy at the end of 2025.

[3] Regulation Notice posted to the Environmental Registry of Ontario: <https://ero.ontario.ca/notice/025-0501>.

1. Section 14(2)5(iii): Arrangements between OPG and DNNP LP

The rate-setting framework established in the regulation contemplates OPG acting as the sole project manager and operator of the DNNP facilities consistent with the DNNP LP entering into agreements with OPG for provision of such services. The DNNP LP is not expected to have its own workforce. As such, section 14(2)5(iii) requires acceptance of these agreements, as follows:

> [In setting payment amounts for the DNNP Nuclear Generating Station, the Board shall,] accept the terms, conditions and pricing methodologies included in any project management, operations, revenue allocation or lease agreements between the DNNP generator and Ontario Power Generation Inc. in respect of the DNNP Nuclear Generating Station.

Additionally, the following amendments address the recovery of DNNP costs through regulated payment amounts and various deferral and variance accounts.

2. Section 11 and section 14(2)3: DNNP Development Variance Account

Under section 11, the Darlington New Nuclear Project Variance Account re Development is established to record the difference between (i) the revenue requirement impacts arising from the actual non-capital and capital costs incurred and firm financial commitments made for the Darlington New Nuclear Project, and (ii) the amount of revenue requirement impacts arising from non-capital and capital costs and firm financial commitments that were included in OEB-approved payment amounts. As specified in section 11(1)(a)(ii) and 11(1)(b)(ii), the variance account will also record net revenues earned or foregone by DNNP LP due to deviations from the OEB-approved forecast output from the DNNP facilities associated with differences between the actual in-service date and the OEB-approved forecast in-service date of the DNNP facilities.

Further in relation to the recovery of DNNP facilities costs and the Darlington New Nuclear Project development variance account, section 14(2)3 states:

> The Board shall ensure that the DNNP generator recovers the non-capital and capital costs incurred and firm financial commitments made for the Darlington New Nuclear Project, including but not limited to the costs incurred for the matters referred to in sub-subclauses 11 (1) (a) (i) (A) to (C), to the extent that the Board is satisfied that,
>
> i. the costs were prudently incurred and directly attributable to the Darlington New Nuclear Project, and
>
> ii. the financial commitments were prudently made and directly attributable to the Darlington New Nuclear Project.

Consistent with the requirements of this section of the regulation, the Application describes the established Darlington New Nuclear Project Variance Account re Development in Ex. H1-1-1, Section 6.1, including details on how the account will treat deviations in production resulting from differences between forecast and actual in-service date.

3. <u>Section 13: DNNP Generator Capital Structure Variance Account</u>

   Under section 13, the DNNP generator capital structure variance account is established to record differences between the revenue requirement impacts arising from a capital structure and cost of debt reflecting the amount of borrowing incurred by DNNP LP and the amount of the revenue requirement impacts arising from the capital structure and the cost of debt that were included in OEB-approved payment amounts.

> (1) The DNNP generator shall establish a variance account in connection with section 78.1 of the Act that, until the effective date of the first DNNP post-construction payment order, records differences between,

> (a) the revenue requirement impacts arising from the DNNP generator's capital structure and cost of debt reflecting the actual amount and cost of borrowing issued by it; and
>
> (b) the amount of the revenue requirement impacts arising from the capital structure and the cost of debt that were included in payments made under section 78.1 of the Act to the DNNP generator.
>
> (2) The account shall not include any amount included in a variance account established under subsection 11(1) or 12(1).
>
> (3) The DNNP Lessee shall record interest on the balance of the account as the Board may direct.

As discussed in Ex. C1-1-1, informed by this requirement, 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 (Ex. C1-1-1, Attachment 3).

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 DNNP Generator Capital Structure Variance Account.

4. <u>Section 12 and Section 14(2)5: DNNP Concurrent Cost Recovery</u>

   Under section 14(2)5, the DNNP LP revenue requirement shall include an amount calculated by multiplying the forecast cumulative capital costs incurred by DNNP LP in respect of the DNNP by OPG's long-term debt rate. Under section 12, the Darlington New Nuclear Project Variance Account re Capital Cost Amounts is established to record the difference between an amount calculated by multiplying the actual cumulative capital costs incurred by DNNP LP in respect of the DNNP and the forecast amount included in OEB-approved payment amounts.

Recovery of the balance in the Darlington New Nuclear Project Variance Account re Capital Cost Amounts is specified under section 14(2)5ii, to be recovered on an annual basis in the year following the year in which any amount was recorded.

Consistent with the requirements of this section of the regulation, the Application proposes such concurrent cost recovery ("CCR") amounts to be included in DNNP LP revenue requirement, as discussed in Section 5.0 below and in Ex. I1-1-3.[4] In addition, the Application describes the established Darlington New Nuclear Project variance account re capital cost amounts in Ex. H1-1-1, Section 6.3.

5. Section 14(2)7 Blended Base Payment Amounts

Under section 14(2)7, the OEB shall determine a blended base payment amount for OPG and DNNP LP on a five-year basis, through the following formula:

$$(A + B) / (C + D)$$

"A" is the OEB-approved revenue requirement for the nuclear facilities for the year
"B" is the OEB-approved revenue requirement for the DNNP facilities for the year
"C" is the OEB-approved production forecast for the nuclear facilities for the year
"D" is the OEB-approved production forecast for the DNNP facilities for the year

Consistent with the requirements of this section of the regulation, the Application proposes an accommodating rate setting framework in Ex. A1-3-2 and a blended nuclear payment amount in Ex. I1-3-1.

6. Section 0.1 and 6(2)10.1: Nuclear Liabilities

Under the terms of the Lease, OPG will be responsible for the nuclear waste management and decommissioning obligations arising from the DNNP facilities. In section 0.1 of O. Reg. 53/05, the definition of "nuclear decommissioning liability" for OPG has been updated to include decommissioning of the DNNP facilities.

[4] With respect to subsequent units, the Application only includes CCR associated with funds released to date for Units 2-4.

In section 6(2)10.1 of O. Reg. 53/05, the following paragraph has been added with respect to the recovery of such nuclear decommissioning liability costs:

> The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs in relation to its nuclear decommissioning liability with respect to the Bruce Nuclear Generating Stations and the DNNP Nuclear Generating Station as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc., to the extent that those costs are not otherwise recovered under this subsection.

To address the requirements of this section of the regulation, the Application proposes a DNNP Nuclear Liability Deferral Account in Ex. H1-1-1, Section 7.5. In accordance with section 10.1, the costs recorded in the proposed account would be as reflected in OPG's audited financial statements.[5]

7. Section 14(2)2: Asset Transfer and Leasehold Improvements

Under section 14(2)2, the OEB is instructed to accept the following as capital costs in determining the revenue requirement of DNNP LP:

> i. The following costs incurred by Ontario Power Generation Inc. in respect of the Darlington New Nuclear Project, to the extent that the Board is satisfied that the costs were prudently incurred:
>
> A. Costs in respect of any asset transferred from Ontario Power Generation Inc. to the DNNP generator, as reflected in the audited schedule of costs that is approved by Ontario Power Generation Inc.'s board of directors as at the transfer date.
>
> B. Costs in respect of any asset licensed by Ontario Power Generation Inc. to the DNNP generator, as reflected in the audited schedule of costs that is approved by Ontario Power Generation Inc.'s board of directors as at the licensing date.

[5] As discussed in Ex. C2-1-1, OPG has not yet developed comprehensive cost estimates for the future nuclear liabilities for the DNNP facilities, and none have been recorded in OPG's financial statements. As such, OPG has not reflected any corresponding amounts in the proposed IR term nuclear revenue requirements.

> C. Any other costs for which the DNNP generator has reimbursed Ontario Power Generation Inc., as reflected in the audited schedule of costs that is approved by Ontario Power Generation Inc.'s board of directors as at the reimbursement date.
>
> ii. Costs relating to any leasehold improvements made by the DNNP generator in relation to the DNNP Nuclear Generating Station, including with respect to design, development, construction, commissioning or sustaining, to the extent that the Board is satisfied that the costs were prudently incurred.

Consistent with the requirements of this section, the Application treats the Asset Transfer amount and the forecast of leasehold improvements to be made by DNNP LP as the basis for the capital costs that will make up the in-service amount added to rate base (Unit 1 forecast to come into service in October 2030) and for purposes of determining the amounts to be recovered through CCR. The Asset Transfer is discussed further in Section 4.0, below.

4.0 CAPITAL EXPENDITURES AND OM&A EXPENSES

4.1 Capital Expenditures

Through the agreements listed in Section 2.0, DNNP LP will reimburse OPG for all construction in progress costs through the issuance of ownership units. The applicable costs must have been capitalized by OPG and relate to the DNNP facilities costs, including:

- performing front-end design or engineering work, including front-end engineering design studies, or process engineering work for the DNNP including collecting and analyzing of site data, simulating and analyzing the performance and cost of process design options, selecting the optimum process design and conducting feasibility studies or pre-feasibility studies;
- clearing or excavating land;
- constructing a temporary access road to the DNNP site;
- the procurement of long lead items and site preparation activities; and
- progressing construction execution.[6]

[6] See Ex. D2-4-1 to Ex. D2-4-9 for more information on the DNNP, including expenditures to date and current status.

Pursuant to O. Reg. 53/05, Section 14(2)2i, the balance of the Asset Transfer will be accepted as DNNP LP capital costs. Thus, the Asset Transfer balance will act as the opening construction-in-progress ("CIP") balance for DNNP LP, ultimately forming part of the DNNP rate base as applicable assets come into service. This also acts as the opening balance for purposes of determining DNNP CCR amounts in Ex. I1-1-1, Table 6 (see Section 5.7 for further discussion on DNNP CCR).

Pursuant to O. Reg. 53/05, Section 14(2)2ii, costs relating to any leasehold improvements made by DNNP LP in relation to the design, development, construction, commissioning or sustaining the DNNP facilities will be accepted as capital costs, ultimately forming part of the DNNP rate base as applicable assets come into service. Consistent with this requirement, following the Asset Transfer, the leasehold improvements made by DNNP LP to develop and construct Unit 1 will form the basis of the in-service addition amount for Unit 1 (in addition to the opening Asset Transfer balance discussed above). These capital expenditures are also reflected in the calculation of DNNP CCR amounts in Ex. I1-1-1, Table 6. In accordance with US GAAP, the leasehold improvements will be capitalized as property, plant & equipment.

4.2 OM&A Expenses

DNNP LP's operation and maintenance expenditures will reflect (among other things) the costs arising from OPG's services to DNNP LP under the applicable agreements. Prior to achieving commercial operations, OM&A expenses for operational readiness will be incurred to ensure safe, reliable and effective operation of the units once they are online. This includes the implementation of comprehensive training programs, tailored to the operation and maintenance requirements of the SMRs, creating a specialized workforce with technology specific expertise. OM&A expenses also include planning activities such as developing operational processes and procedures, establishing work management functions for scheduling routine and outage maintenance, planning for emergency management and fire protection, implementing plant maintenance protocols, defining oversight systems, and establishing operational targets.

In addition to operational readiness related costs, the proposed OM&A expenses prior to the achievement of commercial operations include a share of OPG's Support Services costs and asset service fees determined in accordance with OPG's established cost allocation methodology,[7] as well as the financial impact to OPG of retaining the outstanding early works construction financing previously provided to OPG by Canada Infrastructure Bank ("CIB") for the DNNP. Subsequent to the forecasted Asset Transfer, this financing adjustment will ensure the impact of the CIB debt remains associated with the DNNP facilities, as part of the DNNP LP revenue requirement.

Fuel Expense:

Under the terms of the MOMA, ownership and responsibility of all nuclear fuel used in the operation of the DNNP facilities will remain with OPG. The costs associated with fuel supply and operations, including cost of capital on the fuel inventory held by OPG for DNNP LP, will be charged to DNNP LP through a nuclear fuel service fee. The fee will be computed in cost-based manner that is intended to result in an impact similar to what would have been included in the DNNP LP's revenue requirement had it owned the fuel.

Property Tax:

Under the terms of the Lease agreement, DNNP LP is responsible for paying municipal property taxes payable to the Municipality of Clarington. Municipal property taxes are governed by the *Assessment Act*[8] and apply a fixed rate to the ground floor of generating buildings while non-generating buildings are assessed at market value.

In the following section, the costs outlined above are discussed in terms of where they fit within the DNNP LP revenue requirement requested for approval in this Application.

[7] OPG's cost allocation methodology is described in Ex. F3-1-4 and has been independently validated by Elenchus Research Associates.
[8] R.S.O 1990, c.A.31.

5.0 REVENUE REQUIREMENT

As presented in Ex. A1-2-2, this Application contains approvals on behalf of both OPG and DNNP LP. The combined application produces regulatory efficiencies and is consistent with the requirements of O. Reg. 53/05, section 14(2)7, which requires the OEB to "determine a blended base payment amount for Ontario Power Generation Inc. and the DNNP generator" during the DNNP construction period. This section discusses the DNNP LP revenue requirement and production forecast requested in this Application.

DNNP LP seeks approval of the following items in the following exhibits:

Chart 1: DNNP LP Approval Summary

Issue	Evidence
Rate Base	Ex. B1-1-1 and Ex. B1-1-1 Table 3
Capital Structure and Return on Equity	Ex. C1-1-1
OM&A Expenses	Ex. F2-2-1 and Ex. F2-1-1 Table 1b
Nuclear Fuel Service Fee	Ex. F2-5-1 and Ex. F2-3-1 Table 1
Depreciation and Amortization	Ex. F4-1-1 and Ex. F4-1-1 Table 2
Tax Expense	Ex. F4-2-1
Concurrent Cost Recovery	Ex. I1-1-3 and Ex. I1-1-1 Table 6
Revenue Requirement	Ex. I1-1-1 and Ex. I1-1-1 Table 2a
Production Forecast and Methodology	Ex. E2-1-1 and Ex. E2-1-1 Table 1

For the DNNP facilities, the Application seeks approval of proposed revenue requirements of $302M for 2027, $381.4M for 2028, $417M for 2029, $582.1M for 2030, and $1,076.1M for 2031, as presented at Ex. I1-1-1, Table 2a. The DNNP production forecast proposed in this Application is 0TWh in 2027-2029, 0.5TWh in 2030 and 1.9TWh in 2031, as shown in Ex. E2-1-1 Table 1, line 4.

DNNP LP is also seeking to establish several deferral and variance accounts as described in Ex. H1-1-1, which are generally intended to mirror the accounts in place or proposed to be in place for OPG.

LIST OF ATTACHMENTS

Attachment 1: DNNP LP 2026-2031 Business Plan

Confidential Exclusive

DNNP GP Inc.
FOR APPROVAL by the Board of Directors

January 12, 2026

DECISION REQUIRED

The purpose of this submission is to seek approval of DNNP LP's 2026-2031 business plan (the plan), by DNNP GP Inc. (DNNP GP) in its capacity as the sole managing general partner of DNNP LP. The plan reflects the recently submitted joint application to the Ontario Energy Board (OEB) for regulated rates for DNNP LP and Ontario Power Generation Inc.'s (OPG) facilities, pursuant to Ontario Regulation 53/05 under the *Ontario Energy Board Act, 1998* (O. Reg. 53/05), covering the 2027-2031 period (OEB Application).

ISSUE

DNNP LP was formed on October 16, 2025, under the laws of the Province of Ontario (Province). The business of DNNP LP involves designing, developing, constructing, commissioning, operating, maintaining and managing up to four BWRX-300 small modular reactors (SMRs), as approved, on lands leased from OPG (collectively, the DNNP Facilities). In April 2025, the Canadian Nuclear Safety Commission (CNSC) issued a power reactor construction licence to OPG for such first SMR (Unit 1) and in May 2025, the Province announced its support for proceeding with Unit 1's execution phase. The business plan presented herein reflects the approved release quality estimate (RQE) budget and construction timeline for Unit 1 (including common site scope necessary to support all four planned SMRs) and the associated financial and electricity generation forecasts for the 2026-2031 business planning timeframe.

This first business plan for DNNP LP reflects cost forecasts for the DNNP Facilities, as provided by OPG, which will help meet Ontario's growing electricity needs in alignment with the Province's Integrated Energy Plan (IEP) and support provincial and national energy security and economic growth objectives, all while delivering financial value to the owners of DNNP LP. Unit 1 has an approved project budget of approximately $7.7 billion and is scheduled to enter commercial operation in October 2030. The construction of subsequent SMRs is subject to future approvals and is not reflected in this business plan (the development and construction of Unit 1 and potential subsequent units being the Darlington New Nuclear Program or DNNP). The plan reflects OPG acting as sole Project Manager and Operator of the DNNP Facilities pursuant to arrangements in place for the provision of such services to DNNP LP and, subject to the OEB's acceptance that the conditions required by O. Reg. 53/05 for DNNP GP, as general partner on behalf of DNNP LP, to become a prescribed generator have been satisfied.

ANALYSIS

OVERVIEW OF PARTNERSHIP AND BUSINESS STRUCTURE

Overview: DNNP LP is a limited partnership formed under the laws of the Province of Ontario, currently between OPG, DNNP GP Inc., and 1001368516 Ontario Inc. (the initial limited partner, wholly owned by OPG), for the purposes of designing, developing, constructing, commissioning, operating, maintaining and managing the DNNP Facilities. Additional expected limited partners of DNNP LP, and shareholders of DNNP GP, are discussed below.

The goal of DNNP LP is to deliver the first grid-scale SMR in the G7, with the four-unit DNNP Facilities expected to have a total output of approximately 1,200 MW. According to the Province, the construction of the four SMRs would create up to 18,000 Canadian jobs and inject an average of $500 million annually into Ontario's economy and contribute $38.5 billion to Canada's gross domestic product over 65 years. DNNP LP is not expected to have its own workforce and, as discussed below, has contracted with OPG to build and operate the DNNP Facilities through a series of agreements.

Ontario Regulation 53/05: In December 2025, the Province amended O. Reg. 53/05 to add DNNP GP, as general partner on behalf of DNNP LP, as a prescribed generator to be regulated by the OEB in order to enable commercial partnerships for the DNNP Facilities, subject to meeting certain conditions, and set out the applicable rate-setting framework. The framework includes:

- Requiring a blended regulated rate between the DNNP Facilities and OPG's nuclear facilities, until the effective date of the OEB's first order setting regulated rates for the DNNP Facilities after the DNNP has been completed;
- Establishing a Darlington New Nuclear Project Variance Account re Development (DNNPVARD) to record (i) the difference between the revenue requirement impacts arising from the actual non-capital and capital costs incurred and financial commitments made for the DNNP, and those included in the OEB-approved regulated rates, and (ii) net revenues earned or foregone by DNNP LP due to deviations from the OEB-approved forecast production associated with differences between the actual in-service date and the OEB-approved forecast in-service date of the DNNP Facilities;
- Establishing a DNNP Generator Capital Structure Variance Account (DGCSVA) to record the difference between the revenue requirement impacts arising from a capital structure and cost of debt reflecting the amount of borrowing incurred by DNNP LP and those arising from the capital structure and cost of debt included in the OEB-approved regulated rates, until the effective date of the OEB's first order setting regulated rates for the DNNP Facilities after the DNNP has been completed;
- Establishing a concurrent cost recovery (CCR) framework that allows DNNP LP to recover interest amounts during the construction phase of the DNNP Facilities, calculated by multiplying the incurred capital expenditures by OPG's long-term debt rate as approved by the OEB. The CCR framework includes establishment of a Darlington New Nuclear Project Variance Account re Capital Cost Amounts (DNNPVARC) to capture differences in such interest amounts as a result of differences between forecast and actual capital expenditures; and
- Requiring the OEB's acceptance of certain items for the purpose of setting regulated rates for DNNP LP, including: (i) the terms, conditions and pricing methodologies included in any project management, operations, revenue allocation or lease agreement in respect of the DNNP Facilities between DNNP LP and OPG; and (ii) the treatment as DNNP LP's capital costs of the prudently incurred costs in respect of the assets transferred or licensed by DNNP LP from OPG or otherwise reimbursed to OPG in respect of the DNNP and of the leasehold improvement costs incurred by DNNP LP in relation to the DNNP Facilities.

Subject to the OEB's acceptance, DNNP GP has satisfied the conditions set out in O. Reg. 53/05 as being required for it to become a prescribed generator.

Key Agreements with OPG: DNNP GP, as managing general partner of DNNP LP, has entered into the following arrangements to effect its contractual relationship with OPG in relation to the DNNP Facilities as of the end of 2025:

- Leased the lands on which the DNNP Facilities are being constructed from OPG through a long-term lease agreement (Lease), together with OPG having transferred and licensed certain assets related to the DNNP to DNNP LP and the parties having entered into an agreement for DNNP LP to reimburse OPG for all construction in progress costs for the DNNP as of such time (Asset Transfer). The Asset Transfer also establishes the DNNP LP's asset value for tax purposes;
- Entered into a project management agreement (PMA) and a management, operations, maintenance and administration agreement (MOMA) pursuant to which OPG will carry out the design, development, commissioning, construction, management, operation and maintenance of the DNNP Facilities on behalf of DNNP LP and will be the licensee in respect of the CNSC licences pertaining to the DNNP and the DNNP Facilities. DNNP LP is responsible for paying the associated

costs including reimbursing OPG for its fully allocated costs, without profit, incurred in connection with these activities;
    - Through the PMA, OPG has been granted authority as sole Project Manager to manage, oversee and deliver all project management services for the development, design, construction and commissioning of the DNNP Facilities, subject to defined controls and approvals;
    - The MOMA details the scope of the services, authority and responsibilities of OPG, as sole Operator, to manage, operate, maintain, secure, insure, administer, ensure regulatory compliance, engage with Indigenous communities and undergo OEB rate-setting with respect to the DNNP Facilities, subject to defined controls and approvals. OPG expects to file a Unit 1 operating licence application with the CNSC in 2026; and
- Entered into an IESO payments collection, allocation and settlement agreement (PAA) under which OPG will act as an agent in connection with the collection of DNNP LP's revenue received from the Independent Electricity System Operator (IESO) pertaining to the sale of electricity generation from the DNNP Facilities and settlement of ancillary amounts with the IESO for as long as a blended regulated rate is in effect. The agreement includes methodologies for allocating revenues received from the IESO pursuant to a blended regulated rate between DNNP LP and OPG. DNNP GP, as general partner on behalf of DNNP LP, will apply for and hold the OEB generation licence for the DNNP Facilities.

OPG will have the ownership and responsibility for all nuclear fuel used in the operation of the DNNP Facilities, including the associated nuclear fuel carry inventories. All costs associated with fuel supply and operations, including a cost of capital associated with the carry inventories, will be charged to the DNNP LP by OPG through a nuclear fuel service fee. OPG will also retain the obligations for nuclear decommissioning and management of used fuel and other nuclear waste associated with the DNNP Facilities.

Additional Investors: The plan reflects Equity Commitment Agreements (ECAs) entered by OPG and each of Canada Growth Fund Inc. (CGF) and Building Ontario Fund (BOF) (collectively, the Government Agencies) on September 17, 2025. Under the ECAs, the Government Agencies will subscribe for partnership equity units of DNNP LP and common shares of DNNP GP, as non-controlling investors. It is anticipated that, during the business plan period, OPG will hold 77.5%, CGF will hold 15.0% and BOF will hold 7.5% of the partnership units of DNNP LP and common shares of DNNP GP, which is reflected in the OEB Application. Subject to satisfaction of certain conditions in the ECAs, it is anticipated that the Government Agencies' initial subscriptions to the equity partner units and common shares will occur in the first quarter of 2026.

OVERVIEW OF DARLINGTON NEW NUCLEAR PROGRAM EXECUTION

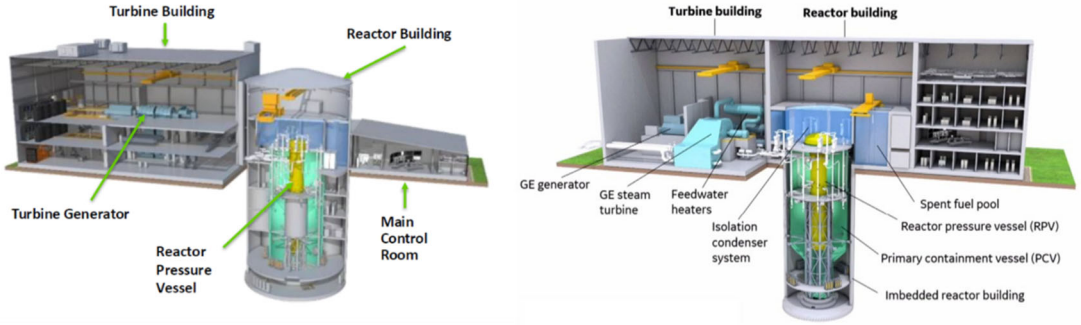
The DNNP is currently executing the construction of Unit 1 and the common scope facilities (i.e., those common site facilities necessary to support the first unit as well as the remaining three units). The common scope facilities include the condenser cooling water intake and discharge structures, and common buildings such as administration, fabrication and security buildings. Based on the high confidence schedule, Unit 1 is planned to be placed in commercial operation on October 17, 2030. The CNSC power reactor construction licence for Unit 1 is valid until March 31, 2035.

Unit 1 is being executed via an integrated project delivery (IPD) commercial model in which the key parties involved in the design, fabrication and construction of a project work together under a single Integrated Project Agreement (IPA), with the aim of driving collaboration, efficiency, shared accountability and the sharing of risks. The non-owner participants (NOP) under the IPA are the technology designer (GE-Hitachi),

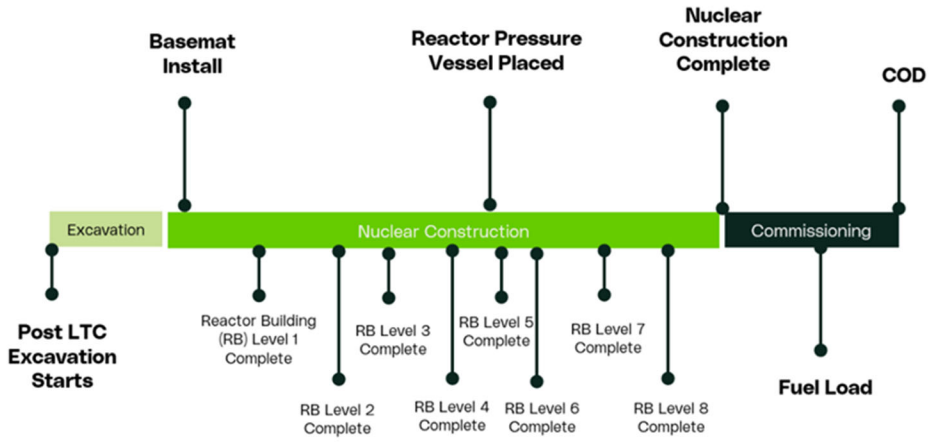
the architect/engineer (AtkinsRéalis / Candu Energy Inc.) and the constructor (AECON Kiewit Nuclear Partners). The IPA includes a shared risk and reward framework to motivate cost, schedule and performance by all parties through to the completion of the project, based on a series of reward and risk pools established utilizing project contingency and NOP's overhead costs/profit, respectively.

Consistent with the recommendation of Project Management Institute, OPG is using the Major Work Bundle approach to manage the DNNP. The scope of each bundle is in turn broken down into individual projects and each project has an identified party accountable for delivering the scope. Design Engineering, Nuclear Island, Conventional Island, and Balance of Plant bundles contain most of the remaining design and construction work and is the focus of the Unit 1 execution phase.

The Nuclear Island Bundle is comprised of the structures and components within the nuclear island, including the reactor building, control building, radiation waste building, and plant services building. The reactor building will house the reactor pressure vessel, primary containment, safety systems, and essential piping and instrumentation. The control building will house the main control room, emergency response facilities, and electrical, control and instrumentation equipment. The Conventional Island Bundle is comprised of the structures and components within the conventional island, including the turbine building, the security building and scope associated with grid connection. The Balance of Plant Bundle is comprised of various temporary and permanent general site facilities and infrastructure, the condenser cooling water system, and power block and yard construction. The scope of the once-through condenser cooling water system includes the excavation of the intake and outfall tunnels and construction of offshore and onshore infrastructure that will use lake water for condenser cooling purposes. A simplified schematic of the BWRX-300 and a more detailed illustrative cross section of the power block are shown below.



The major critical path phases of Unit 1 execution comprise completing the excavation for the reactor building, installing the basemat as the primary foundation support at the base of the reactor unit, constructing the reactor building, placing the reactor pressure vessel, completing equipment installation and nuclear construction, testing and commissioning of the unit prior to and post fuel load, and ultimately placing the unit into commercial operation. A simplified Unit 1 construction schedule sequence is shown below. This business plan aligns to the approved high confidence schedule to complete Unit 1.



The Unit 1 RQE budget of $7.7 billion includes appropriate contingency, is based on Class 3 estimate quality requirements as defined by Association for the Advancement of Cost Engineering International and reflects the high confidence schedule to deliver Unit 1. The budget includes both IPA and non-IPA costs, with the Nuclear Island, Conventional Island, Balance of Plant, and Owner Program & IPD Project Management Office bundles comprising the majority of the Major Work Bundle costs. This business plan aligns to the approved RQE budget to complete Unit 1.

In parallel with the execution of Unit 1 and as previously endorsed by the Province, OPG is undertaking planning and preparations for the remaining three units of the DNNP during their definition phase, on behalf of DNNP LP. OPG's CNSC licence to prepare site for the DNNP is valid until October 2031.

OPG has in place a comprehensive risk management system, structured change management process and multi-level oversight model to ensure that the DNNP meets the safety, quality, cost and schedule expectations and that accurate and timely information is available to support effective decision-making by OPG, as Project Manager, and DNNP LP, as the owner. The PMA identifies the protocols to be followed for provision of project information to the DNNP GP's Board of Directors.

REGULATED RATE-SETTING

Rate-Setting Framework: The plan reflects the approvals sought in the OEB Application. The application was prepared and submitted in December 2025 to the OEB by OPG on behalf of itself and DNNP LP and includes a request for a blended regulated rate for the DNNP Facilities and OPG's nuclear facilities. It reflects the requirements of O. Reg. 53/05 and requests an effective date for the OEB's rate order of January 1, 2027. For the nuclear facilities, the application seeks approval of each year's base nuclear regulated rate using annual revenue requirements and individual year production forecasts. The blended regulated rate is achieved by adding the respective entities' nuclear revenue requirements and production forecasts, as applicable. The plan reflects the methodologies set out in the PAA for allocating the forecasted revenues that would be received from the IESO based on the OEB Application between DNNP LP and OPG.

Other than the CCR interest amounts on definition phase expenditures for the subsequent SMRs, the OEB Application's approvals in respect of DNNP LP are limited to the first SMR.

Concurrent Cost Recovery: Beginning in 2027, the requested annual revenue requirements include the recovery of CCR interest amounts on forecast cumulative DNNP capital expenditures prior to the DNNP

Facilities being placed in service, including costs reimbursed to OPG in connection with the Asset Transfer. With the applicable provisions of O. Reg. 53/05 effective January 1, 2026, the CCR interest amounts on DNNP capital expenditures incurred prior to the effective date of the OEB's rate order on the OEB Application will be recorded in the DNNPVARC, to be recovered during the following year, which is reflected in the plan. The CCR mechanism will provide DNNP LP with an additional source of funding during construction, strengthening the ability to deliver the DNNP in a cost-effective manner. As a consequence of the CCR framework, construction period interest costs have been removed from the in-service rate base proposed for the DNNP Facilities, resulting in a reduction in the total costs recoverable from ratepayers over the facilities' operating life.

CCR interest amounts on any additional expenditures for the subsequent SMRs during the business plan period will be recorded for recovery through the DNNPVARC.

Proposed Deferral and Variance Accounts: The OEB Application proposes several deferral and variance accounts for DNNP LP that mirror existing and proposed new accounts for OPG. Additionally, the application seeks a variance account to address the revenue requirement impact of any changes in the tax status (i.e., taxable or tax-exempt) of current or future partners of DNNP LP. At present, CGF and BOF are tax-exempt and therefore the proposed DNNP LP's revenue requirements sought in the OEB Application and reflected in the plan do not consider income taxes in respect of the anticipated ownership share of these future partners.

Treatment of Clean Electricity Investment Tax Credits: The OEB Application does not include the impact of a proposed 15% federal refundable tax credit for eligible expenditures on clean electricity investments (CEITC), including SMRs, that could be available to partners of DNNP LP. No legislation implementing this credit is currently in place and, as discussed below, the impacts of the CEITCs are not reflected in this business plan. The OEB Application proposes to return to customers the revenue requirement impact of the CEITCs for the DNNP, once available, through the DNNPVARD and DNNPVARC, as applicable. The revenue requirement impact of the CEITCs will be realized through a reduction in the depreciation expense and cost of capital related amounts once the assets are placed in service, while reducing the available capital cost allowance deductions for income tax purposes. Additionally, the CEITCs will reduce the amount of DNNP capital expenditures for purposes of CCR interest amount recovery.

CAPITAL EXPENDITURES AND RATE BASE

Capital Expenditure and In-Service Amounts: The capital expenditure and in-service amounts in the plan reflect the approved Unit 1 RQE budget and construction schedule (including common site scope necessary to support all four SMRs). As noted, due to the recovery of interest amounts under the CCR framework, construction period interest costs have been removed from the in-service rate base proposed for the DNNP Facilities and accordingly capital expenditures and in-service amounts do not include interest costs. The resulting forecast capital expenditures are approximately $4.8 billion over the business plan period and the forecast capital in-service amount for the first SMR is approximately $6.6 billion in 2030. The in-service assets are assumed to be depreciated over the 60-year design life of the SMR, subject to further accounting assessment as Unit 1 progresses toward commercial operation. There are no planned sustaining capital expenditures for the DNNP Facilities during the business plan period.

The planned capital expenditures are approximately $4.4 billion for the construction and commissioning of Unit 1 over the 2026-2030 period and approximately $0.4 billion for definition phase activities for the three subsequent SMRs over the 2026 and 2027 years. The planned capital expenditures to complete Unit 1 are approximately $1.5 billion in 2026, $1.4 billion in 2027, $900 million in 2028, $300 million in 2029 and $375

million in 2030. As noted, the plan does not reflect construction phase capital expenditures or any in-service amounts for the subsequent SMRs, which are subject to future approvals. The capital expenditure forecasts are based on information provided by OPG and will be updated in subsequent business plans, as necessary, to reflect the progression of project activities.

Project cost performance for the first SMR will be measured on an interest-included basis, including CCR interest amounts, against the $7.7 billion budget.

Rate Base: As noted, O. Reg. 53/05 requires the OEB to accept as DNNP LP's capital costs OPG's prudently incurred costs in respect of the assets transferred or licensed by DNNP LP from OPG or otherwise reimbursed to OPG as part of the Asset Transfer and of the leasehold improvement costs incurred by DNNP LP in relation to the DNNP Facilities. These costs for Unit 1 form the DNNP LP's forecasted in-service rate base in the OEB Application and the plan, based on Unit 1's expected start of commercial operation. Such forecast rate base is approximately $6.5 billion by 2031, reflecting the above noted capital in-service amount (net of depreciation) as well as a forecast of materials and supplies inventory and a cash working capital estimate. Consistent with O. Reg. 53/05 requirements, the costs in respect of the Asset Transfer forming part of the DNNP LP's proposed rate base include interest costs capitalized by OPG as part of its associated construction in progress balance prior to January 1, 2026; these interest costs are not recoverable by DNNP LP or OPG under the CCR framework. In accordance with US GAAP, DNNP LP's leasehold improvement costs will be capitalized as property, plant and equipment. As noted, the revenue requirement impact of differences between the actual and forecast capital costs for the DNNP is subject to the DNNPVARD.

FINANCING, LIQUIDITY AND DISTRIBUTIONS

Sources and Uses of Funds: The plan contemplates that funding requirements for the DNNP capital expenditures will be met by equity contributions from the partners, which total $5.3 billion over the business plan period (inclusive of the Government Agencies' initial equity subscriptions pursuant to the respective ECAs). The plan assumes that ongoing equity contribution capital calls are funded at the beginning of each calendar quarter. DNNP GP expects to develop a distribution policy for DNNP LP that will distribute to the partners available operating cash flow, including as a result of the CCR mechanism, net of any necessary reserves. The plan assumes that the distributions are made quarterly, totaling $2.5 billion over the business plan period.

Debt Financing Expectations: The plan does not forecast debt financing for DNNP LP during the 2026-2031 period. As a first-of-a-kind project within a stand-alone entity, DNNP has an inherently higher perceived risk profile that is expected to limit access to debt markets during construction and prior to a sufficient period of operating history. DNNP GP expects to develop a leverage policy for DNNP LP that will seek to secure investment-grade debt market financing following sufficient operating history for the first SMR, assumed to be after 2031. In line with these expectations and informed by the requirements of O. Reg. 53/05, the OEB Application seeks a 100% equity funded capital structure for DNNP LP's rate base for the planned operating period between October 2030 and December 2031 covered by the application. As noted, the revenue requirement impact of differences between the actual and forecast capital structure during this period is subject to the DGCSVA.

Clean Electricity Investment Tax Credits: As noted, neither the plan nor the OEB Application reflect the impact of the proposed federal CEITCs, as the implementation of these credits has not yet been legislated. Should these credits become legislated, they are expected to be available to partners of DNNP LP with respect to eligible DNNP expenditures. In addition to the nature of the expenditures, CEITC eligibility for the DNNP will be determined based on whether the respective partner qualifies to receive the CEITC. The

CEITCs would be claimed directly by the partners and accounted for as a reduction to the DNNP LP's capital assets.

Operating Cash Flow and Distributions: Prior to the start of Unit 1's commercial operation, forecasted positive operating cash flow is based on the collection of CCR interest amounts. Over the 2027-2029 period, such annual operating cash flow averages $316 million. As noted, in accordance with O. Reg. 53/05, CCR interest amounts in respect of the 2026 year will be collected in 2027. Negative operating cash flow of $111 million in 2026 is due, in part, to the anticipated revenue requirement recovery for DNNP LP forecasted OM&A expenses not commencing until the assumed effective date of the OEB's order on the OEB Application of January 1, 2027. For the first full year of commercial operation of the first SMR in 2031, forecasted operating cash flow is $900 million. More detailed expectations of working capital requirements will be developed in subsequent business plans. Based on the expected operating cash flow, the plan forecasts partner distributions averaging $311 million over the 2027-2029 period, increasing to over $699 million annually in 2030 and 2031.

As a partnership, DNNP LP is not itself subject to income taxes. Each partner is instead required to account for their share of the partnership taxable income or loss as part of their respective tax obligations. DNNP LP's operating cash flow resulting from the recovery of any income taxes through the OEB-approved revenue requirements will be distributed to the taxable partners.

NET INCOME

DNNP LP's forecast net income prior to the start of commercial operation of the first SMR is based on the recoverability of CCR interest amounts. Net income is approximately $224 million per year, on average, over the 2026-2029 period, increasing over these years as CCR increases with the cumulative capital expenditures. Forecast net income increases further beginning in 2030 as Unit 1 commences commercial operation, entering rate base and beginning to earn a return on equity. For the first full year of earning a return on equity, net income is expected to reach $615 million in 2031. The financial results for the business plan period will be subject to the outcome of the OEB Application, including the approved cost of capital parameters.

ELECTRICITY GENERATION

The SMRs are designed as baseload generating facilities. During the business plan period, energy generation of 0.5 TWh is forecast in 2030 upon the commencement of Unit 1 commercial operation in October 2030, followed by 1.9 TWh in 2031 for the first full year of operations. Based on current design information, this reflects a net electrical rating of 315 MW for the SMR. As noted, net revenue differences due to deviations between the actual and forecast in-service dates of the DNNP Facilities are subject to the DNNPVARD.

Based on industry experience and considering the first-of-a-kind nature of the project, the forecasted generation plan for Unit 1 reflects lower availability assumptions in the initial operating years, with a forced loss rate of 12% in the first year of operation and 6% in the second year. The generation plan also includes a 15-day outage in early 2031 to address equipment issues that are likely to emerge following the start of commercial operation.

Like other Boiling Water Reactors, the SMRs will require periodic refueling outages. The first such cyclical planned outage is forecast in the fall of 2031, with a duration of 50 days. It is expected to include the initial re-fueling, prescribed inspection and maintenance, and potential additional regulatory inspections over first-of-a-kind operations and reflects first-time start-up related activities. The outage forecasting is based on

available related industry operating experience and input from the original equipment manufacturer. After the initial cyclical planned outage, the SMR is expected to be on a two-year planned outage cycle.

Operating performance measures and targets for the DNNP Facilities will be developed as Unit 1 approaches commercial operation.

OPERATING COSTS

Fuel Expense: As noted, OPG, as Operator, will maintain ownership and responsibility for all nuclear fuel used in the operation of the DNNP Facilities and the associated carry inventories, charging a nuclear fuel service fee to DNNP LP under the MOMA. The fee will be computed in a cost-based manner and is intended to result in an amount similar to the revenue requirement impact of such costs had DNNP LP owned the fuel. The forecasted fee as provided by OPG reflects a projection of inventory levels for the first SMR at the applicable stages of the BWRX-300 fuel supply chain including for the initial fuel load and, beginning in 2030, a fuel consumption cost representing the energy portion of the projected cost of fuel assemblies as determined based on preliminary estimates provided by the fuel fabricator. The resulting nuclear fuel service fees are forecast to increase from $9 million in 2027 to $50 million in 2031.

Operations, Maintenance & Administration (OM&A) Costs: The OM&A costs represent fully allocated amounts expected to be payable by DNNP LP for the management, operations, maintenance and administration of the DNNP Facilities and DNNP LP by OPG beginning in 2026. These amounts will be payable under the MOMA, with the exception of the operational readiness costs discussed below that will be payable under the PMA. The planned OM&A costs are those necessary to perform these functions in connection with Unit 1 and reflect substantial fixed costs that would be required to operate any one of the four possible reactors. The incremental OM&A costs in connection with subsequent SMRs would therefore be lower. The planned OM&A costs increase beginning in 2030 to reflect Unit 1's scheduled commercial operation date and are based on information provided by OPG.

Station Costs: Station OM&A costs represent OPG's direct, dedicated labour and non-labour base resources that will operate and maintain the first SMR once it enters commercial operation. These forecasted resourcing levels reflect an optimized station staffing structure developed by OPG based on a minimum complement strategy which will leverage the BWRX-300 plant design. This streamlined operating model is expected to be enabled by such elements as plant design simplification, passive fail-safe systems, digitization and automation, and broadened unionized job classifications. The station base costs are forecast at $18 million in 2030 and $66 million in 2031.

Outage Costs: The plan reflects OM&A expenses of $49 million in 2031 to carry out refueling, inspection and maintenance activities for Unit 1 during the first cyclical outage planned in 2031. As noted, the forecasting of this outage is based on available related industry operating experience and input from the original equipment manufacturer. OPG expects that contracting services will be used for the maintenance scope of this initial outage.

Support Costs: Support OM&A costs represent an attribution of labour and non-labour resources of OPG's operations and project support functions as well as OPG's corporate support service functions. Operations and project support functions provide specialized services across OPG's generating fleet and ensure a common procedural framework within which the generating facilities operate and projects are executed. Corporate support service functions deliver common support services and maintain OPG's corporate infrastructure and core organizational processes. Operations and project support costs include OPG's functions in areas such as enterprise engineering, fleet management, security, training, and health and safety. Corporate support costs include OPG's functions in areas such as governance, oversight and

compliance, human resources, information technology, financial and risk management, legal services, supply chain management, and stakeholder and Indigenous relations.

Forecast operations and project support costs average approximately $5 million over the 2026-2029 period, before increasing to $16 million in 2030 and $53 million in 2031 as the first SMR enters commercial operation. Forecast corporate support costs increase from $23 million in 2026 to $32 million in 2031. For the period leading up to the start of Unit 1's commercial operation, these costs are intended to ensure that the amounts paid by DNNP LP under the MOMA capture a fully allocated level of organizational effort associated with the DNNP-related activities across OPG's functions. The support costs will be attributed by OPG to DNNP LP in accordance with OPG's cost allocation methodology based on principles acceptable to the OEB. Under this framework, costs will be directly assigned to the DNNP Facilities through specific identification or estimation of resources where reasonably possible, or otherwise will be allocated to the DNNP Facilities, amongst OPG's other business activities, using standardized cost drivers that reflect cost causality.

Operational Readiness Costs: Prior to Unit 1 achieving commercial operation, OM&A expenses will need to be incurred to ensure safe, reliable and effective operation of these first-of-a-kind facilities once they are online. This includes the hiring of operational staff by OPG ahead of the commercial operation date and implementing comprehensive tailored training programs to create a specialized workforce with the necessary technology specific expertise. Once staff completes the training, they will support operational readiness activities and/or transition to DNNP commissioning activities. Operational readiness costs will also cover planning activities such as developing operational processes and procedures, establishing work management functions, planning for emergency management and fire protection, implementing plant maintenance protocols, defining oversight systems, and establishing operational targets. Forecast operational readiness costs for Unit 1 range between $29 million and $46 million annually over the 2026-2030 period and wind down by 2031 as the reactor enters commercial operation. These costs are expected to be subject to the DNNPVARD.

Insurance Costs: Under the terms of the PMA and the MOMA, OPG is responsible for obtaining and maintaining comprehensive insurance coverage for the DNNP Facilities. The estimated cost of such insurance based on current assumptions is included in the plan. The plan assumes that the DNNP Facilities will hold their own insurance policies, including for nuclear liability and nuclear property insurance, subject to regulatory requirements and market availability. Beginning on the commercial operations date of the first SMR, the resulting forecast insurance expenses are $5 million in 2030 and $11 million in 2031. These estimates and assumptions will be updated in subsequent business plans, as necessary, to reflect further development of the insurance structure, market conditions and additional specificity anticipated with respect to the applicable regulatory requirements, including updated statutory nuclear liability limits under the *Nuclear Liability and Compensation Act*.

Asset Service Fees: Asset service fees represent annual amounts that will be charged to DNNP LP by OPG under the MOMA for the dedicated or shared use of certain OPG assets in the performance of OPG's services as Project Manager and Operator of the DNNP Facilities. The dedicated use assets forecast over the business plan period includes OPG's digital infrastructure that is being developed exclusively, or near-exclusively, to operate and maintain the DNNP Facilities and which will not be leased to DNNP LP. The shared assets forecast over the business plan period includes OPG's common enterprise digital infrastructure and its corporate headquarters property. The fees are computed in a cost-based manner and intended to result in an amount similar to the revenue requirement impact of such capital costs had DNNP LP owned a portion of these assets. Accordingly, the fees commence once the corresponding assets enter service.

Technology will play a critical role in enabling the SMRs' operational requirements and optimizing their performance. Among the dedicated use digital infrastructure being developed by OPG is a new enterprise asset management solution for managing the lifecycle of physical assets for the DNNP Facilities that will support the SMRs' operating model, including the streamlined workforce plan, while ensuring compliance with regulatory standards. This portfolio also includes technologies to support functions such as engineering modeling, digitalization of plant operations, work protection, chemistry and radiation protection.

The asset service fees for dedicated use assets are forecast at $9 million in 2030 and $41 million in 2031, reflecting the placement in service of the digital infrastructure upon Unit 1 commencing commercial operation. The forecast asset service fees for shared use assets range from $7 million to $11 million annually over the business plan period. The usage allocations for the shared assets to the DNNP Facilities, amongst OPG's other business activities, will be performed by OPG in accordance with its cost allocation methodology based on principles acceptable to the OEB.

Additionally, pursuant to the MOMA, beginning in 2026, the plan reflects an annual financing adjustment from OPG to DNNP LP associated with OPG's existing non-revolving credit facility with the Canada Infrastructure Bank (CIB) that was previously established to fund OPG's early-works for the DNNP. This amount is a credit over the business plan period, calculated based on the net financial impact to OPG resulting from the outstanding debt under the CIB facility and is reflected in DNNP LP's revenue requirements sought in the OEB Application.

Property Tax Expense: Under the terms of the Lease, DNNP LP is responsible for paying property taxes on the lands and properties leased from OPG. Beginning on Unit 1's commercial operation date, the forecast property tax expense is $1 million in 2030 and $4 million in 2031, as provided by OPG based on current assumptions.

DNNP GP Inc.
FOR APPROVAL by the Board of Directors

RECOMMENDATION / RESOLUTION

That the Board of Directors of DNNP GP Inc. approve the 2026-2031 business plan for DNNP LP, as presented.

Recommended by:

Michael Gore

SVP Chief Controller & Accounting Officer
Ontario Power Generation Inc.

Approved by:

James Brewer

President & CEO
DNNP GP Inc.

Appendices

1. Financial Information

Appendix 1 – Financial Information

Income Statement *(millions of dollars, years ending December 31)*	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Revenue[1]	113	301	379	404	558	1,037
Fuel	-	9	14	13	18	50
Total gross margin	**113**	**292**	**365**	**391**	**540**	**987**
OM&A expenses	33	80	84	74	121	259
Depreciation and amortization	-	-	-	-	23	110
Property tax	-	-	-	-	1	4
Total expenses	**33**	**80**	**84**	**74**	**145**	**372**
Income before interest	**80**	**211**	**281**	**317**	**395**	**615**
Net interest expense	(3)	(2)	-	-	-	-
Income before tax	**83**	**213**	**281**	**317**	**395**	**615**
Income tax	-	-	-	-	-	-
Net income	**83**	**213**	**281**	**317**	**395**	**615**

1. Includes IESO non-energy charges such as Global Adjustment, of less than $1M and $3M in 2030 and 2031 respectively

OM&A Expenses *(millions of dollars, years ending December 31)*	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Operations and Support Costs						
Station OM&A	-	-	-	-	18	66
Outage OM&A	-	-	-	-	-	49
Operations and projects support	4	4	5	5	16	53
Support services	23	28	31	29	30	32
	27	**33**	**36**	**34**	**64**	**199**
Other OM&A						
Operational Readiness	29	46	46	40	40	-
Insurance	-	-	-	-	5	11
Asset Service Fee - Dedicated use assets	-	-	-	-	9	41
Asset Service Fee - Shared use assets	7	9	11	11	11	8
Financing adjustment	(4)	(7)	(10)	(12)	(11)	(4)
Other[1]	(1)	(0)	(0)	0	3	3
OEB deferral and variance account offsets	(24)	-	-	-	-	-
	6	**48**	**48**	**40**	**57**	**59**
Total OM&A expenses	**33**	**80**	**84**	**74**	**121**	**259**

1. Includes DNNP LP's portion of OPG's centrally-held pension & OPEB and management performance incentive costs

DNNP GP Inc.
FOR APPROVAL by the Board of Directors

Balance Sheet *(millions of dollars, as at years ending December 31)*	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Assets						
Current assets						
Cash	344	340	336	332	50	50
Materials and supplies	-	-	-	4	18	32
Other assets	156	101	98	124	188	-
	499	441	434	460	256	82
Construction in progress	3,884	5,505	6,401	6,706	494	494
Property, plant and equipment in service (net)	-	-	-	-	6,562	6,453
Other assets						
Regulatory assets	140	29	30	30	30	30
Total Assets	**4,523**	**5,975**	**6,865**	**7,196**	**7,343**	**7,058**
Partners' Equity	**4,523**	**5,975**	**6,865**	**7,196**	**7,343**	**7,058**

Financing and Liquidity Outlook *(millions of dollars, as at years ending December 31)*	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Opening cash balance	-	344	340	336	332	50
Operating Activities						
Net operating cash inflows	(111)	378	283	288	339	899
Cash flow provided by (used) in operating activities	(111)	378	283	288	339	899
Investing activities						
Unit 1 and Common Scope Facilities	(1,455)	(1,410)	(897)	(305)	(373)	-
Unit 2-4[1]	(178)	(210)	-	-	-	-
Cash flow used in investing activities	(1,633)	(1,621)	(897)	(305)	(373)	-
Financing Activities						
Partnership contributions	2,088	1,566	894	334	451	0
Distributions	-	(327)	(285)	(321)	(699)	(900)
Cash flow provided by (used) in financing activities	2,088	1,239	609	13	(248)	(900)
Net cash inflow (outflow) for period	**344**	**(4)**	**(4)**	**(4)**	**(282)**	**(1)**
Ending cash balance	**344**	**340**	**336**	**332**	**50**	**50**

1. Approved funding release for Units 2-4 Definition Phase work

OPG Corporate Organizational Chart

A description of the organizational structure, showing the main units, executive and senior management positions within OPG, as well as operating subsidiaries

PRESIDENT & CEO

ENTERPRISE PROJECTS
Chief Projects Officer & Chief Nuclear Officer

- Renewable Generation Major Projects
- Nuclear Projects
- Enterprise Project Management Office

ENTERPRISE OPERATIONS
Chief Operations Officer

- **Nuclear Operations** *Chief Nuclear Officer*
  - Nuclear Regulatory Affairs
  - Nuclear Oversight
  - Nuclear Sustainability Services
  - Nuclear Sustainability Strategies
  - Darlington
  - Pickering
- **Renewable Generation Operations**
  - Western Region
  - Eastern Region
  - Niagara Operations
  - Dam Safety & Water Resources
  - RG Programs & Strategy
  - Energy Markets
- **Integrated Fleet Management**
  - Emergency Services, Security & Training
  - Fleet Performance
  - Enterprise Learning
- **Environment, Health & Safety**
- **Enterprise Engineering**
  - Advanced Inspection & Maintenance
  - Design & Project Engineering
  - Central Engineering
  - Station Engineering
  - New Nuclear Technologies & Deployment
  - Nuclear Refurbishment
  - Darlington New Nuclear Project
  - Industrial & Commercial Engineering

CORPORATE SERVICES
Chief Financial Officer & Chief Administrative Officer

- Human Resources & Real Estate
- Corporate & Technology Services
- Finance

COMMERCIAL OPERATIONS & REGULATORY AFFAIRS
Chief Commercial Officer

- Supply Chain
- Commercial Management
- Regulatory Affairs

ENTERPRISE STRATEGY & NEW NUCLEAR DEVELOPMENT
SVP Enterprise Strategy & Growth

- Enterprise Strategy
- Nuclear Business Development
- Nuclear Strategic Sites

CORPORATE AFFAIRS & HYDRO BUSINESS DEVELOPMENT
SVP Business Development & Corporate Affairs

- Indigenous Relations
- Stakeholder & Government Relations
- Hydro Business Development

LAW, GOVERNANCE & ESG
Chief Legal, ESG & Governance Officer

- Law
- Corporate Governance & Corporate Secretary
- Environmental, Social & Governance

OPERATING SUBSIDIARIES

- Atura Power
- Eagle Creek Renewable Energy[1]
- Laurentis Energy Partners
- PowerON Energy Solutions
- DNNP GP Inc.
- Origin Nuclear Inc.

[1] In October 2025, OPG entered into an agreement for the sale of OPG's US-based subsidiary, Eagle Creek Renewable Energy, which OPG expects to close in 2026.

SUMMARY OF LEGISLATIVE FRAMEWORK

1.0 PURPOSE

The purpose of this evidence is to provide a summary of the extensive legislative and regulatory framework as well as other government requirements that govern OPG and DNNP LP, and apply to OPG's prescribed facilities and the Darlington New Nuclear Program ("DNNP") facilities. The evidence also summarizes relevant best practices and guidelines to which OPG adheres.

This evidence is substantially the same as that filed in EB-2020-0290, with the following exceptions: the discussion of amendments to Ontario Regulation 53/05 ("O. Reg. 53/05") made subsequent to EB-2020-0290 in Section 3.0 (Attachment 1), including the addition of DNNP LP as a prescribed generator; a discussion of the *Building Canada Act* in Section 9.3; and the discussion of the repeal of the *Protecting a Sustainable Public Sector for Future Generations Act, 2019* in Section 10.2.

2.0 INTRODUCTION

OPG is subject to provincial and federal legislation and regulations, including the decisions of administrative tribunals or other regulatory bodies whose powers are derived from such legislation or regulations (e.g., the Ontario Labour Relations Board, the IESO, and the Canadian Nuclear Safety Commission ("CNSC")), and to Canada's international obligations under certain international treaties (e.g., regarding international boundary waters and nuclear safeguards). Compliance with the legislative framework can drive the need for certain programs and capital and non-capital expenditures, and impact OPG's operations.

3.0 ONTARIO ENERGY BOARD ACT

The *Ontario Energy Board Act, 1998* (the "Act"), when read in conjunction with O. Reg. 53/05, as made under the Act, as amended, establishes that OPG is a prescribed generator for the purposes of section 78.1 of the Act (Attachment 2). Effective January 1, 2026, DNNP LP is a prescribed generator for purposes of section 78.1 of the Act, subject to conditions set out in section 8 of O. Reg. 53/05. The combination of the Act and O. Reg. 53/05 provide that OPG

and DNNP LP are entitled to receive just and reasonable payments, subject to specific rules in O. Reg. 53/05, with respect to the output from the prescribed generating facilities.

Since EB-2020-0290, O. Reg. 53/05 was amended on November 4, 2021, effective January 1, 2022, to include the DNNP as a regulated facility prescribed for the purposes of section 78.1 of the Act. Further details related to this variance account are found in Ex. H1-1-1.

In September 2022, the Government of Ontario asked OPG to operate Pickering Units 5-8 until the end of September 2026 (instead of December 2025), subject to approval by the CNSC. O. Reg 53/05 was further amended on December 8, 2022, effective January 1, 2023, to require the establishment of a Pickering B Extension Variance Account to track the additional revenues and costs associated with operating Pickering for the additional period. Further details related to this variance account are found in Ex. H1-1-1. O. Reg 53/05 was further amended, effective July 1, 2025, to record Pickering station-level and corporate costs that OPG is incurring in the 2024-2026 period for retaining the capacity and readiness to operate the Pickering Units 5-8 post-refurbishment.

O. Reg 53/05 was further amended, effective May 2, 2025, to replace references to "congestion management settlement credits" (“CMSCs”) with "CMSCs or make-whole payments, as the case may be" to align with new settlement processes introduced under the Market Renewal Program (“MRP”). MRP is referenced in Section 5.0, below, and discussed in greater detail in Ex. E1-2-1.

In December 2025, O. Reg. 53/05 was amended to: (i) provide a framework for recovery of interest amounts associated with the Pickering Refurbishment Program (“PRP”) and the DNNP prior to such assets being placed in service[1]; and (ii) establish a framework for the OEB to rate-regulate DNNP LP.[2]

[1] Further details on the amendments related to recovery of interest amounts before assets placed in service can be found in Ex. I1-1-3.
[2] Further details on the amendments establishing the framework for rate-regulating DNNP LP can be found in Ex. A1-4-4.

4.0 ELECTRICITY ACT

Part IV.1 of the *Electricity Act, 1998* applies directly to OPG. The provisions set out in this part of the *Electricity Act, 1998* establish the objects of OPG as well as certain obligations on OPG to provide reports to its shareholder.

5.0 ELECTRICITY MARKETS

Under authority granted to it by the *Electricity Act, 1998*, the IESO administers and ensures compliance with the Market Rules for the Ontario Electricity Market (the "Market Rules"). All of OPG's prescribed generating facilities are registered in the IESO-controlled markets and are therefore required to comply with all applicable Market Rules.

On May 1, 2025, the IESO implemented broad changes to Ontario's electricity market, known as the MRP. MRP is discussed in greater detail in Ex. E1-2-1.

6.0 OEB LICENCE

OPG holds an Electricity Generation Licence (EG-2023-0231) from the OEB, which is valid until October 2, 2043 (the "Licence"). The Licence can be found in Attachment 3.

The Licence applies to all generating stations that are owned and/or operated by OPG, including the prescribed facilities. The Licence obligates OPG to comply with all applicable provisions of the Act, the *Electricity Act, 1998*, all regulations under these acts, and all applicable Market Rules. The Licence further obligates OPG to enter into agreements for the supply of energy or ancillary services where the IESO deems necessary for the purpose of maintaining the reliability and security of the IESO-controlled electricity grid. On April 30, 2025, the OEB ordered the amendment of the Licence to include changes to the Must-Offer Condition required as a result of MRP. On August 28, 2025, the OEB further ordered the Licence be amended to include a limited scope exemption from the ring-fencing provisions to allow OPG to share non-public information about planned outages at Sir Adam Beck II Generating Station with NV LP (also known as Atura Power), which is constructing a hydrogen production facility next to the station.

DNNP LP will apply to the OEB for an electricity generation licence in respect of the operation of the DNNP facilities prior to the first unit entering commercial operation. As OPG will be the owner of the DNNP facilities, OPG will request an amendment to its generation licence to reflect ownership of the DNNP facilities in a parallel application.

7.0 REGULATED HYDROELECTRIC GENERATING FACILITIES

OPG's prescribed hydroelectric facilities are subject to international treaties between Canada and the United States; federal and provincial regulatory and legislative requirements; and common law as it pertains to riparian interests, waterways, and real property. The key regulatory obligations and constraints applicable to the prescribed hydroelectric facilities are highlighted below.

7.1 Water Rights and Usage

Relevant legislation and agreements include:

- *Public Lands Act* (Ontario);
- *Lakes and Rivers Improvement Act* (Ontario);
- *Niagara Parks Act* (Ontario);
- *Boundary Waters Treaty of 1909 between Great Britain and the United States* (sanctioned by the Parliament of Canada);
- *Niagara Diversion Treaty of 1950* between Canada and the United States;
- *Niagara Development Act, 1951* (Ontario);
- Agreement between OPG and the Niagara Parks Commission, February 2005;
- *International Rapids Power Development Agreement Act, 1952*, between Canada and Ontario;
- *St. Lawrence Development Act, 1952 (No. 2)* (Ontario);
- *Dominion Water Power Act* and *Dominion Water Power Regulations* (Canada);
- *Ottawa River Water Powers Act, 1943* (Ontario and Quebec);
- Agreement Respecting Ottawa River Basin Regulation, 1983 (Canada, Ontario, Quebec) pertaining to management and regulation of the waters within the Ottawa River basin;

- Agreement Regarding the Review of the Rent for the Water Powers of the Ottawa River, executed November 2020 (Ontario, Quebec, Hydro Quebec and OPG)
- *Lake of the Woods Control Board Act* (Canada, 1921, and Ontario, 1922) and amendments (Ontario, 1958);
- *Tripartite Agreement (Canada, Ontario, and Manitoba),1922*, pertaining to control of upper waters of the Winnipeg River;
- *Lac Seul Conservation Act, 1928* (Canada);
- *Manitoba-Ontario Lake St. Joseph Diversion Agreement Authorization Act, 1958* (Manitoba);
- *Electricity Act, 1998*, section 92.1, which addresses the gross revenue charge;
- Water Power Leases and Water Power Lease Agreements, Crown Leases and Licences of Occupation with Ontario Ministry of Natural Resources;
- Licences with Parks Canada for facilities on the Trent River and Rideau Canal;
- Lease agreement with St. Lawrence Seaway Management Corporation for diversion of water from the Welland Ship Canal for utilization at DeCew Falls; and
- Agreements between OPG and other utilities/generators (New York Power Authority, Manitoba Hydro, Hydro-Québec) related to operational requirements/guidelines, joint works, water sharing, water diversions, and compensation settlements.

7.2 Dam Safety

OPG's Safe Operations Policy and the associated Dam Safety Program Management document require that all OPG dams be designed, constructed, operated, and maintained in accordance with all regulations. In the absence of a specific regulation, the Canadian Dam Association ("CDA") Dam Safety Guidelines (2013), the CDA Guidelines for Public Safety Around Dams (2011), or other appropriate industry standards shall apply. These guidelines and OPG's internal standards provide guidance on dam safety covering inspections, testing of flow control equipment, emergency preparedness planning, periodic reviews of safety, and other aspects considered critical for ensuring the safety of the prescribed hydroelectric facilities and their operations.

In Ontario, provincial legislative authority over dams is exercised through the *Lakes and Rivers Improvement Act* and the supporting Regulation 454/96. In August 2011, the Province of Ontario enhanced the direction to dam owners with the provision of new Technical Guidelines for Approval under the *Lakes and Rivers Improvement Act*.

In Quebec, provincial legislative authority over dams is exercised through the *Quebec Dam Safety Act* and the supporting Quebec Dam Safety Regulation. This covers OPG facilities on the Ottawa River.

The Government of Canada exercises authority over dams through the *Canadian Navigable Waters Act* and the *Canada Shipping Act, 2001*, including associated regulations. These acts apply to OPG in relation to the construction of new dams, alterations to existing dams, and the administration of "approved works", such as safety booms and exclusion zones associated with OPG's measures to manage public safety. The Government of Canada has jurisdiction over all boundary waters as well as waters associated with canals. In addition to operating the Sir Adam Beck facilities on the Niagara River and the R.H. Saunders facility on the St. Lawrence River, OPG also operates a number of structures on the Trent Severn Waterway and the Rideau Canal which come under federal jurisdiction. In the case of the OPG facilities located on the Trent Severn Waterway and Rideau Canal, the guidelines that OPG is required to follow are administered by Parks Canada's Dam Safety Directive (2009).

Relevant dam safety guidelines and legislation include:

- CDA Dam Safety and Public Safety Around Dams Guidelines;
- *Lakes and Rivers Improvement Act* (Ontario);
- Province of Ontario Dam Safety Technical Guidelines;
- *Canadian Navigable Waters Act* (Canada);
- *Canada Shipping Act, 2001* and the Vessel Operation Restriction Regulations;
- International Joint Commission regulation of the Niagara and St. Lawrence Rivers, pursuant to the *Boundary Waters Treaty of 1909;*
- *Dam Safety Act* (Quebec) and Dam Safety Regulation;
- *Civil Protection Act* (Quebec); and
- Directive for Dam Safety Program of Parks Canada Dams and Water-Retaining Structures.

8.0 NUCLEAR GENERATING FACILITIES

8.1 Nuclear Operations and Materials

OPG's nuclear operations are subject to the jurisdiction of the CNSC, an independent federal government agency that derives its powers from, and is responsible for administering, ensuring compliance with and enforcing the *Nuclear Safety and Control Act*, which is described below. Several of the key regulatory regimes that are uniquely applicable to OPG's nuclear facilities are discussed below.

The *Nuclear Safety and Control Act* is intended to limit the risks to national security, the health and safety of persons and the environment that are associated with the development, production and use of nuclear energy, as well as to limit risks associated with the production, possession and use of nuclear substances, certain equipment and certain related information. This act also implements measures to which Canada has agreed respecting international control of the development, production and use of nuclear energy, including the non-proliferation of nuclear weapons and nuclear explosive devices. In addition, this act establishes the CNSC and delineates its powers.

The CNSC's regulatory control extends to regulating all aspects of site preparation, construction, operation (including maintenance, and refurbishment for life extension), and decommissioning of nuclear facilities.

The CNSC exercises its mandate in respect of OPG's nuclear operations by means of the issuance of operating licences and amendments, as well as through continuous monitoring and inspections to ensure compliance with operating licences, along with relevant legislative standards, applicable regulations, and CNSC regulatory documents (all of which form part of OPG's licensing basis). The regulator issues requests for action and information on a routine basis. Operating licences impose numerous conditions and constraints on OPG, including obligations to comply with relevant legislation, applicable regulations, and regulatory documents issued by the CNSC and various external standards and codes (e.g., National Building Code, National Fire Code, Canadian Standards Association Standards). The CNSC has issued a number of regulatory documents for nuclear power plants, including for example,

ones relating to maintenance programs, reliability programs, aging management, safety analysis, and emergency preparedness.

For refurbishment of nuclear power plants for life extension, the regulatory process and CNSC expectations have been documented in Regulatory Document *2.3.3 Periodic Safety Reviews*, (which superseded RD-360, Life Extension of Nuclear Power Plants) (see Ex. D2-3-1, Attachment 1 and Attachment 4). This document outlines expectations for, and CNSC acceptance of, Periodic Safety Reviews against modern codes and standards, including requiring a safety factor review, a global assessment report, and the ensuing integrated implementation plan for the corrective actions and safety improvements. Regulatory control by the CNSC is exercised through amended operating licences by including licence conditions that have to be met.

The CNSC also issues guidance documents that provide direction to licensees and applicants on how to meet the requirements set out in applicable regulations, the CNSC's regulatory documents, and licences. It is OPG's practice to incorporate the directions from these guidance documents into the design and operating documents for its nuclear generating stations.

OPG must maintain compliance in order to ensure that the nuclear facility is fit for service and continued operation.

OPG currently holds two Power Reactor Operating Licences from the CNSC, which allow for the operation of Pickering and Darlington, as well as separate licences that authorize the operation of nuclear waste management facilities. OPG also maintains regulated certificates for radioactive material transportation packages, and licences for the possession, transport, and import/export of certain radioactive materials. OPG also holds a licence to construct a new nuclear power plant at the Darlington site. OPG regularly seeks licence amendments, as well as new licences, from the CNSC on an as-needed basis in order to ensure ongoing regulatory compliance.

In addition to the resources and costs associated with complying with the conditions in these licences, the application process for each licence, including significant amendments or renewal, requires extensive preparation and the conduct of public hearings involving CNSC staff, intervening stakeholders, and Indigenous rightsholders. OPG is required to pay a licence fee to the CNSC each year, under the CNSC's Cost Recovery Fees Regulations, which in effect covers the CNSC's costs of staff and resources to administer the licence including compliance activities and inspections. Further, as set out above, OPG's nuclear facilities are required to operate in accordance with numerous regulations under this act, including:

- General Nuclear Safety and Control Regulations;
- Class 1 Nuclear Facilities Regulations;
- Packaging and Transport of Nuclear Substances Regulations, 2015;
- Nuclear Security Regulations;
- Radiation Protection Regulations;
- Nuclear Substances and Radiation Devices Regulations;
- Class II Nuclear Facilities and Prescribed Substances Regulations;
- Nuclear Non-proliferation Import and Export Control Regulations; and
- CNSC Cost Recovery Fees Regulations.

A person or organization may only possess or dispose of nuclear substances, or construct, operate and decommission nuclear facilities in accordance with the terms of a licence issued by the CNSC. Licences incorporate the applicable requirements set out in the regulations.

It is a fundamental principle of nuclear regulation that the licensee, in this case OPG, bears responsibility for the safe operation of nuclear facilities. The CNSC sets safety objectives in areas such as radiation protection, physical site security, and the transport of radioactive materials. OPG is required to design, implement, monitor, and continually improve upon its extensive programs in each of these critical areas. The CNSC audits OPG's performance against these objectives, continually monitors OPG's safety performance, and reports annually to Parliament with an assessment of licensee performance in all areas of nuclear safety. The delivery and continual improvement of these programs represent a significant cost driver for OPG in respect of the nuclear facilities.

8.2 Civil Liability

OPG is subject to the *Nuclear Liability and Compensation Act* (Canada), which governs civil liability for damages in Canada related to nuclear incidents. The legislation requires OPG (and all other operators of nuclear generating stations in Canada) to maintain specified amounts of nuclear liability insurance purchased from a federal government approved insurer or other equivalent forms of financial security approved by the federal government.

8.3 Nuclear Waste Management

The *Nuclear Safety and Control Act* provides the CNSC with authority over nuclear waste from a health, safety and environmental protection perspective. The CNSC licences all of OPG's waste management facilities. OPG also has obligations under the *Nuclear Fuel Waste Act* (Canada) which addresses the long-term handling and disposal of used nuclear fuel.

Coincident with the formation of OPG on April 1, 1999, OPG and the Province of Ontario entered into the Ontario Nuclear Funds Agreement ("ONFA"). The ONFA is an agreement that generally establishes the responsibilities for funding OPG's nuclear waste management and decommissioning liabilities, which were inherited from Ontario Hydro. The ONFA is discussed in greater detail in Ex. C2-1-1.

8.4 Security Personnel

Beyond the nuclear-specific federal requirements described above, two pieces of provincial legislation apply in respect of the security personnel associated with OPG's nuclear generating facilities. These are the *Police Services Act* (Ontario) and the *Security for Electricity Generating Stations and Nuclear Generating Stations Act* (Ontario).

9.0 ENVIRONMENTAL

9.1 General

The environmental legislation and best practice standards that impact OPG's nuclear and/or prescribed hydroelectric facilities include:

- *Fisheries Act* (Canada);
- *Conservation Authorities Act* (Ontario);

- *Clean Water Act, 2006* (Ontario);
- *Environmental Assessment Act* (Ontario);
- *Environmental Protection Act* (Ontario);
- *Great Lakes Protection Act, 2015* (Ontario);
- *Ontario Water Resources Act*;
- *Endangered Species Act, 2007* (Ontario);
- *Migratory Birds Convention Act, 1994* (Canada);
- *Species at Risk Act* (Canada);
- *Transportation of Dangerous Goods Act, 1992* (Canada); and
- ISO 14001 Environmental Management System standard, to which OPG has corporate registration.

9.2 The Impact Assessment Act

In *Reference re Impact Assessment Act*, 2023 SCC 23, the Supreme Court of Canada held that portions of the federal *Impact Assessment Act* ("IAA") was unconstitutional because it exceeded the powers allocated to Parliament under section 91 of the *Constitution Act, 1867*. In response, Parliament passed amendments to the IAA that came into force June 20, 2024, focusing impact assessments on areas of federal jurisdiction.

Under the *IAA*, the Impact Assessment Agency of Canada leads the reviews of certain major projects and works in collaboration with CNSC to review such projects that are subject to regulation under the *Nuclear Safety and Control Act*.

9.3 The Building Canada Act

On June 26, 2025, the *Building Canada Act* came into force. The *Building Canada Act* implements a streamlined process for approving projects that are designated as being in the national interest. The Major Projects Office was established to advance these projects. The Major Projects Office's interplay with the DNNP is discussed in Ex. D2-04-01.

10.0 OTHER

10.1 General

OPG's prescribed facilities are also subject to broad range of generally applicable legislative and regulatory requirements in the following areas:

- Technical standards and safety including corresponding regulations and codes, particularly in respect of fuel storage tanks;
- Heritage;
- Dangerous goods transportation;
- Construction and liens;
- Occupational health and safety;
- Employment standards;
- Labour relations;
- Public sector executive compensation;
- Freedom of information; and
- Relevant municipal by-laws.

10.2 The repeal of the *Protecting a Sustainable Public Sector for Future Generations Act, 2019*

The *Protecting a Sustainable Public Sector for Future Generations Act, 2019* ("Bill 124") set limits on compensation increases for unionized and non-unionized employees in the Ontario public sector. Since EB-2020-0290, the Ontario Superior Court, in *Ontario English Catholic Teachers Assoc. v. His Majesty*, 2022 ONSC 6658, held that Bill 124 was unconstitutional. Following that decision, Bill 124 was then repealed on February 23, 2024. The effect of the repeal of Bill 124 is discussed in Ex. F4-3-1.

LIST OF ATTACHMENTS

Attachment 1:	Ontario Regulation 53/05
Attachment 2:	Section 78.1 of the OEB Act
Attachment 3:	OPG Electricity Generation Licence
Attachment 4:	RD-360, Life Extension of Nuclear Power Plants

Ontario Energy Board Act, 1998

ONTARIO REGULATION 53/05
PAYMENTS UNDER SECTION 78.1 OF THE ACT

Consolidation Period: From July 1, 2025 to the e-Laws currency date.

Last amendment: 142/25.

Legislative History: 269/05, 23/07, 27/08, 312/13, 353/15, 57/17, 622/20, 739/21, 557/22, 46/25, 142/25.

This is the English version of a bilingual regulation.

Definitions

0.1 (1) In this Regulation,

"approved reference plan" means a reference plan, as defined in the Ontario Nuclear Funds Agreement, that has been approved by Her Majesty the Queen in right of Ontario in accordance with that agreement; ("plan de renvoi approuvé")

"base payment amount" means the payment amount approved by the Board in respect of output from the hydroelectric facilities or the nuclear facilities, as the case may be, excluding any fixed or variable payment amount rider; ("montant du paiement de base")

"calculation period" means each period for which the Board determines the approved revenue requirements under subparagraph 12 ii of subsection 6 (2) together with the year immediately prior to that period; ("période de calcul")

"Darlington Refurbishment Project" means the work undertaken by Ontario Power Generation Inc. in respect of the refurbishment, in whole or in part, of some or all of the generating units of the Darlington Nuclear Generating Station; ("projet de remise en état de la centrale de Darlington")

"deferral period" means the period beginning on January 1, 2017, and ending when the Darlington Refurbishment Project ends; ("période de report")

"hydroelectric facilities" means the hydroelectric generation facilities prescribed in paragraphs 1, 2 and 6 of section 2; ("installations hydroélectriques")

"nuclear decommissioning liability" means the liability of Ontario Power Generation Inc. for decommissioning its nuclear generation facilities and the management of its nuclear waste and used fuel; ("obligation en matière de déclassement nucléaire")

"nuclear facilities" means the nuclear generation facilities prescribed in paragraphs 3, 4, 5 and 7 of section 2; ("installations nucléaires")

"Ontario Nuclear Funds Agreement" means the agreement entered into as of April 1, 1999 by Her Majesty the Queen in right of Ontario, Ontario Power Generation Inc. and certain subsidiaries of Ontario Power Generation Inc., including any amendments to the agreement; ("Ontario Nuclear Funds Agreement")

"OPG weighted average payment amount" for a year means the total production-weighted average payment amount that is used in the determination of the payments made under section 78.1 of the Act with respect to the generation facilities prescribed in section 2 of this Regulation, calculated according to the formula:

$$(((NPA + NPR) \times NPF) + (HPA + HPR) \times HPF) / (NPF + HPF)$$

where,

NPA is the Board-approved payment amount for the year in respect of the nuclear facilities,

NPR is the Board-approved payment amount rider for the year in respect of the recovery of balances recorded in the deferral accounts and variance accounts established for the nuclear facilities, excluding the deferral account established under subsection 5.5 (1),

NPF is the Board-approved production forecast for the nuclear facilities for the year,

HPA is the Board-approved payment amount for the year, or the expected payment amount resulting from a Board-approved rate-setting formula, as applicable, in respect of the hydroelectric facilities,

HPR is the Board-approved payment amount rider for the year in respect of the recovery of balances recorded in the deferral accounts and variance accounts established for the hydroelectric facilities, and

HPF is the Board-approved production forecast for the hydroelectric facilities for the year; ("paiement moyen pondéré effectué à OPG")

"Pickering B extension activities" means any activities in furtherance of the operation of the Pickering B Nuclear Generating Station during the Pickering B extension period, whether or not the activities occurred during that period; ("activités de prolongation de l'exploitation de Pickering B")

"Pickering B extension period" means the period beginning on January 1, 2026 and ending no later than September 30, 2026; ("période de prolongation de l'exploitation de Pickering B")

"Pickering closure" means the closure or decommissioning of the Pickering A Nuclear Generating Station or Pickering B Nuclear Generating Station, or the retirement of a generating unit at the Pickering A Nuclear Generating Station or Pickering B Nuclear Generating Station from electricity generation; ("fermeture de Pickering")

"Pickering closure activities" means any activities in furtherance of a Pickering closure; ("activités de fermeture de Pickering")

"Pickering B preservation activities" means any activities undertaken by Ontario Power Generation Inc. on or after January 1, 2024 to preserve its ability to operate the Pickering B Nuclear Generating Station following the Pickering B Refurbishment Project, regardless of whether the Pickering B Refurbishment Project proceeds; ("activités de préservation de l'exploitation de Pickering B")

"Pickering B Refurbishment Project" means the work undertaken by Ontario Power Generation Inc. in respect of the refurbishment, in whole or in part, of some or all of the generating units of the Pickering B Nuclear Generating Station; ("projet de remise en état de la centrale de Pickering B")

"small modular reactor" means a nuclear generation facility with an operating capacity of 500 megawatts or less. ("petit réacteur modulaire") O. Reg. 23/07, s. 1; O. Reg. 353/15, s. 1; O. Reg. 57/17, s. 1; O. Reg. 622/20, s. 1; O. Reg. 739/21, s. 1; O. Reg. 557/22, s. 1; O. Reg. 142/25, s. 1.

(2) For the purposes of this Regulation, the output of a generation facility shall be measured at the facility's delivery points, as determined in accordance with the market rules. O. Reg. 312/13. s. 1.

Prescribed generator

1. Ontario Power Generation Inc. is prescribed as a generator for the purposes of section 78.1 of the Act. O. Reg. 53/05, s. 1.

Prescribed generation facilities

2. The following generation facilities of Ontario Power Generation Inc. are prescribed for the purposes of section 78.1 of the Act:

1. The following hydroelectric generating stations located in The Regional Municipality of Niagara:
    i. Sir Adam Beck I.
    ii. Sir Adam Beck II.
    iii. Sir Adam Beck Pump Generating Station.
    iv. De Cew Falls I.
    v. De Cew Falls II.
2. The R. H. Saunders hydroelectric generating station on the St. Lawrence River.
3. Pickering A Nuclear Generating Station.
4. Pickering B Nuclear Generating Station.
5. Darlington Nuclear Generating Station.
6. As of July 1, 2014, the generation facilities of Ontario Power Generation Inc. that are set out in Schedule 1.
7. Any small modular reactors on the lands owned by Ontario Power Generation Inc. in the Municipality of Clarington, Regional Municipality of Durham that are described in Schedule 2. O. Reg. 53/05, s. 2; O. Reg. 23/07, s. 2; O. Reg. 312/13, s. 2; O. Reg. 739/21, s. 2.

Prescribed date for s. 78.1 (2) of the Act

3. April 1, 2008 is prescribed for the purposes of subsection 78.1 (2) of the Act. O. Reg. 53/05, s. 3.

4. REVOKED: O. Reg. 312/13, s. 3.

Deferral and variance accounts

5. (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records capital and non-capital costs incurred and revenues earned or foregone on or after April 1, 2005 due to deviations from the forecasts as set out in the document titled "Forecast Information (as of Q3/2004) for Facilities Prescribed under Ontario Regulation 53/05" posted and available on the Ontario Energy Board website, that are associated with,

(a) differences in hydroelectric electricity production due to differences between forecast and actual water conditions;

(b) unforeseen changes to nuclear regulatory requirements or unforeseen technological changes which directly affect the nuclear generation facilities, excluding revenue requirement impacts described in subsections 5.1 (1) and 5.2 (1);

(c) changes to revenues for ancillary services from the generation facilities prescribed under section 2;

(d) acts of God, including severe weather events; and

(e) transmission outages and transmission restrictions that are not otherwise compensated for through congestion management settlement credits, or make-whole payments, as the case may be, under the market rules. O. Reg. 23/07, s. 3; O. Reg. 46/25, s. 1.

(2) The calculation of revenues earned or foregone due to changes in electricity production associated with clauses (1) (a), (b), (d) and (e) shall be based on the following prices:

1. $33.00 per megawatt hour from hydroelectric generation facilities prescribed in paragraphs 1 and 2 of section 2.
2. $49.50 per megawatt hour from nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2. O. Reg. 23/07, s. 3.

(3) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

(4) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all generating units at the Pickering A Nuclear Generating Station, including those generating units which the board of directors of Ontario Power Generation Inc. has determined should be placed in safe storage. O. Reg. 23/07, s. 3; O. Reg. 557/22, s. 2.

(5) For the purposes of subsection (4), the non-capital costs include, but are not restricted to,

(a) construction costs, assessment costs, pre-engineering costs, project completion costs and demobilization costs; and

(b) interest costs, recorded as simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

5.1 REVOKED: O. Reg. 312/13, s. 3.

Nuclear liability deferral account

5.2 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under 78.1 of the Act, the revenue requirement impact of changes in its total nuclear decommissioning liability between,

(a) the liability arising from the approved reference plan incorporated into the Board's most recent order under section 78.1 of the Act; and

(b) the liability arising from the current approved reference plan. O. Reg. 23/07, s. 3.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 23/07, s. 3.

5.3 REVOKED: O. Reg. 312/13, s. 3.

Nuclear development variance account

5.4 (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under section 78.1 of the Act, differences between,

(a) the revenue requirement impacts arising from the actual non-capital and capital costs incurred and firm financial commitments made for proposed new nuclear generation facilities, including but not limited to the costs of,

(i) planning and preparation for the new facilities,

(ii) technology identification for the new facilities, and

(iii) design, development and construction of the new facilities; and

(b) the amount of the revenue requirement impacts arising from non-capital and capital costs and firm financial commitments that were included in payments made under section 78.1 of the Act. O. Reg. 739/21, s. 3.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 27/08, s. 1.

Darlington refurbishment rate smoothing deferral account

5.5 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the commencement of the deferral period, the difference between,

(a) the revenue requirement amount approved by the Board that, but for subparagraph 12 i of subsection 6 (2) of this Regulation, would have been used in connection with determining the payments to be made under section 78.1 of the Act each year during the deferral period in respect of the nuclear facilities; and

(b) the portion of the revenue requirement amount referred to in clause (a) that is used in connection with determining the payments made under section 78.1 of the Act, after determining, under subparagraph 12 i of subsection 6 (2) of this Regulation, the amount of the revenue requirement to be deferred for that year in respect of the nuclear facilities. O. Reg. 353/15, s. 2.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account at a long-term debt rate reflecting Ontario Power Generation Inc.'s cost of long-term borrowing that is determined or approved by the Board from time to time, compounded annually. O. Reg. 353/15, s. 2.

Pickering closure costs deferral account

5.6 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records any employment-related costs and non-capital costs related to third party service providers incurred by Ontario Power Generation Inc. that arise from any Pickering closure activities, including,

(a) costs related to employee termination, layoff, reassignment or retraining; and

(b) costs related to the hiring of employees or the engagement of third party service providers to perform Pickering closure activities, and their remuneration. O. Reg. 622/20, s. 2.

(2) Subsection (1) applies whether the costs are incurred before or after a Pickering closure, but does not apply to,

(a) costs that are eligible for recovery by Ontario Power Generation Inc. under the Ontario Nuclear Funds Agreement; or

(b) for greater certainty, costs that have already been included in an order made by the Board under section 78.1 of the Act. O. Reg. 622/20, s. 2.

(3) Ontario Power Generation Inc. shall record Pickering closure costs in the deferral account as they are reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc., and shall record interest on the balance of the account as the Board may direct. O. Reg. 622/20, s. 2.

Pickering B variance account

5.7 (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records the difference between,

(a) revenues generated during the Pickering B extension period that are earned from the output of the Pickering B Nuclear Generating Station, calculated on the basis of the base payment amount for the nuclear facilities that applies on January 1, 2026; and

(b) the sum of,

(i) any foregone revenues related to foregone output from the Pickering B Nuclear Generating Station arising from any Pickering B extension activities,

(ii) the revenue requirement impacts arising from the actual non-capital and capital costs incurred in relation to any Pickering B extension activities, and

(iii) the revenue requirement impacts arising from any actual non-capital and capital costs, including but not limited to costs payable for staffing, training, corporate support or administrative functions, incurred in relation to any Pickering B preservation activities before the effective date of the Board's first order under section 78.1 of the Act setting base payment amounts for the nuclear facilities that becomes effective on or after January 1, 2027. O. Reg. 557/22, s. 3; O. Reg. 142/25, s. 2.

(2) The variance account shall,

(a) take into account any related income tax effects; and

(b) not include any amounts included in,

(i) the Board's order under section 78.1 of the Act dated January 27, 2022 setting payment amounts for the nuclear facilities, or

(ii) a deferral account established under section 5.2 or 5.6. O. Reg. 557/22, s. 3.

(3) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 557/22, s. 3.

Rules governing determination of payment amounts by Board

6. (1) Subject to subsection (2), the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act. O. Reg. 53/05, s. 6 (1).

(2) The following rules apply to the making of an order by the Board that determines payment amounts for the purpose of section 78.1 of the Act:

1. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the variance account established under subsection 5 (1) over a period not to exceed three years, to the extent that the Board is satisfied that,
   i. the revenues recorded in the account were earned or foregone and the costs were prudently incurred, and
   ii. the revenues and costs are accurately recorded in the account.
2. In setting payment amounts for the assets prescribed under section 2, the Board shall not adopt any methodologies, assumptions or calculations that are based upon the contracting for all or any portion of the output of those assets.
3. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5 (4). The Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 15 years.
4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs and firm financial commitments incurred in respect of the Darlington Refurbishment Project or incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,
   i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or
   ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

4.1 The Board shall ensure that Ontario Power Generation Inc. recovers the non-capital and capital costs incurred and firm financial commitments made for proposed new nuclear generation facilities, including but not limited to the costs described in subclauses 5.4 (1) (a) (i) to (iii), to the extent the Board is satisfied that,
   i. the costs were prudently incurred, and
   ii. the financial commitments were prudently made.

5. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., the Board shall accept the amounts for the following matters as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors of Ontario Power Generation Inc. before the effective date of that order:
   i. Ontario Power Generation Inc.'s assets and liabilities, other than the variance account referred to in subsection 5 (1), which shall be determined in accordance with paragraph 1.

ii. Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations.

iii. Ontario Power Generation Inc.'s costs with respect to the Bruce Nuclear Generating Stations.

6. Without limiting the generality of paragraph 5, that paragraph applies to values relating to,

i. capital cost allowances,

ii. the revenue requirement impact of accounting and tax policy decisions, and

iii. capital and non-capital costs and firm financial commitments to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2.

7. The Board shall ensure that the balance recorded in the deferral account established under subsection 5.2 (1) is recovered on a straight line basis over a period not to exceed three years, to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded in the account, based on the following items, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc.,

i. return on rate base,

ii. depreciation expense,

iii. income and capital taxes, and

iv. fuel expense.

7.1 The Board shall ensure the balance recorded in the variance account established under subsection 5.4 (1) is recovered on a straight line basis over a period not to exceed three years, to the extent the Board is satisfied that,

i. the costs were prudently incurred, and

ii. the financial commitments were prudently made.

7.2 The Board shall ensure that the balance recorded in the deferral account established under subsection 5.6 (1) and related income tax effects are recovered on a straight line basis over a period not to exceed 10 years beginning on the day the last generating unit of the Pickering A Nuclear Generating Station and Pickering B Nuclear Generating Station permanently stops generating electricity, to the extent that the Board is satisfied that the costs were prudently incurred and are accurately recorded in the account.

8. The Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.

9. The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.

10. If Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations exceed the costs Ontario Power Generation Inc. incurs with respect to those Stations, the excess shall be applied to reduce the amount of the payments required under subsection 78.1 (1) of the Act with respect to output from the nuclear facilities.

11. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc. that is effective on or after July 1, 2014, the following rules apply:

i. The order shall provide for the payment of amounts with respect to output that is generated at a generation facility referred to in paragraph 6 of section 2 during the period from July 1, 2014 to the day before the effective date of the order.

ii. The Board shall accept the values for the assets and liabilities of the generation facilities referred to in paragraph 6 of section 2 as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors before the making of that order. This includes values relating to the income tax effects of timing differences and the revenue requirement impact of accounting and tax policy decisions reflected in those financial statements.

12. For the purposes of section 78.1 of the Act, in setting payment amounts for the nuclear facilities during the deferral period,

i. the Board shall determine the portion of the Board-approved revenue requirement for the nuclear facilities for each year that is to be recorded in the deferral account established under subsection 5.5 (1), with a view to making more stable the year-over-year changes in the OPG weighted average payment amount over each calculation period,

ii. the Board shall determine the approved revenue requirements referred to in subsection 5.5 (1) and the amount of the approved revenue requirements to be deferred under subparagraph i on a five-year basis for the first 10 years of the deferral period and, thereafter, on such periodic basis as the Board determines,

iii. for greater certainty, the Board's determination of Ontario Power Generation Inc.'s approved revenue requirement for the nuclear facilities shall not be restricted by the yearly changes in payment amounts in subparagraph i,

iv. the Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5.5 (1), and the Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 10 years commencing at the end of the deferral period, and

v. the Board shall accept the need for the Darlington Refurbishment Project in light of the Plan of the Ministry of Energy known as the 2013 Long-Term Energy Plan and the related policy of the Minister endorsing the need for nuclear refurbishment.

13. In making its first order under section 78.1 of the Act that is effective on or after January 1, 2022 setting payment amounts for the hydroelectric facilities, the following rules apply:

i. The order shall provide for a base payment amount for the hydroelectric facilities that is equal to the base payment amount for the hydroelectric facilities on December 31, 2021, and that applies until the effective date of a subsequent order setting payment amounts for the hydroelectric facilities that comes into effect after December 31, 2026.

ii. Subparagraph i applies with respect to only 50 per cent of the output of the Chats Falls generation facility.

14. The Board shall determine the disposition of any balance recorded in the variance account established under subsection 5.7 (1), to the extent the Board is satisfied that,

i. the revenues and costs are accurately recorded in the account,

ii. the costs were prudently incurred, and

iii. the amounts recorded in the account are directly attributable to Pickering B extension activities or Pickering B preservation activities. O. Reg. 23/07, s. 4; O. Reg. 27/08, s. 2; O. Reg. 312/13, s. 4; O. Reg. 353/15, s. 3; O. Reg. 57/17, s. 2; O. Reg. 622/20, s. 3 (1); O. Reg. 739/21, s. 4; O. Reg. 557/22, s. 4; O. Reg. 142/25, s. 3.

(3) For greater certainty, the rule set out in paragraph 13 of subsection (2) does not affect any authority of the Board to approve,

(a) changes to the hydroelectric incentive mechanism applicable to Ontario Power Generation Inc.;

(b) the establishment of or changes to deferral or variance accounts relating to the hydroelectric facilities; or

(c) the recovery of any amounts relating to the hydroelectric facilities that are recorded by Ontario Power Generation Inc. in a deferral or variance account referred to in clause (b), or any related payment amount riders. O. Reg. 622/20, s. 3 (2).

7. OMITTED (PROVIDES FOR COMING INTO FORCE OF PROVISIONS OF THIS REGULATION). O. Reg. 53/05, s. 7.

SCHEDULE 1

1. Abitibi Canyon.
2. Alexander.
3. Aquasabon.
4. Arnprior.
5. Auburn.
6. Barrett Chute.
7. Big Chute.
8. Big Eddy.
9. Bingham Chute.
10. Calabogie.
11. Cameron Falls.
12. Caribou Falls.

13. Chats Falls.
14. Chenaux.
15. Coniston.
16. Crystal Falls.
17. Des Joachims.
18. Elliott Chute.
19. Eugenia Falls.
20. Frankford.
21. Hagues Reach.
22. Hanna Chute.
23. High Falls.
24. Indian Chute.
25. Kakabeka Falls.
26. Lakefield.
27. Lower Notch.
28. Manitou Falls.
29. Matabitchuan.
30. McVittie.
31. Merrickville.
32. Meyersberg.
33. Mountain Chute.
34. Nipissing.
35. Otter Rapid.
36. Otto Holden.
37. Pine Portage.
38. Ragged Rapids.
39. Ranney Falls.
40. Seymour.
41. Sidney.
42. Sills Island.
43. Silver Falls.
44. South Falls.
45. Stewartville.
46. Stinson.
47. Trethewey Falls.
48. Whitedog Falls.

O. Reg. 312/13, s. 5; O. Reg. 739/21, s. 5.

SCHEDULE 2

1. PT RDAL BTN: LTS 18 & 19, 20 & 21, 22 & 23, 24 & 25, ALL BF CON (DARLINGTON) CLOSED BY BY-LAW N90910; PT LTS 18, 19, 20, 21, 22, 23 & 24, BF CON (DARLINGTON); LTS 183 TO 754 INCL, 913 TO 1533 INCL, PT LTS 131 TO 133 INCL, 157 TO 182 INCL & 885 TO 912 INCL, STATION RD, FIFTH AVE, SIXTH AVE, SEVENTH AVE, EIGHTH AVE, NINTH AVE, TENTH AVE, ELEVENTH AVE, TWELFH AVE,

THIRTEENTH AVE, FOURTEENTH AVE, FIFTEENTH AVE & SIXTEENTH AVE CLOSED BY BYLAW N90910 & PT SEVENTEENTH AVE, PL 97 (DARLINGTON), PARTS 2, 15, 18 AND 19 PLAN 40R28277 AND PTS 1, 3, 4 & 7 TO 15 INCL, 40R18818, SAVE AND EXCEPT PARTS 1, 2, 3, 4, 5, 13, 14, 15, 16, 17, 18 AND 19 PLAN 40R26289 AND SAVE AND EXCEPT PTS 1, 2, 3, 4, 5, 18 & 19 PLAN 40R28269 AND SAVE AND EXCEPT PTS 8, 9, 10, 11, 12, 13 & 14 PLAN 40R28277; S/T EASE PTS 3, 5, 8, 9 PL 40R20514 AND PTS 14 AND 15 PL 40R28269 AND PT 17 PLAN 40R28277 IN FAVOUR OF PT 9, 40R18818 & PT 1, PL 40R20514 AS IN DR107221; S/T EASE PTS 4, 6, 7, 10 PL 40R20514 AND PT 11 PL 40R20514 SAVE AND EXCEPT PT 8 PL 40R28277 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107221 ; T/W EASE PT LTS 19, 20, 21, PT RDAL BTN LTS 20 & 21, BFC DARLINGTON, PT 1, PL 40R20513 (IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514) AS IN DR107221 ; T/W EASE PT LT 21 BFC DARLINGTON, PT 2, PL 40R20513 (IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514) AS IN DR107221 S/T EASE PT 8, PL 40R18818 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, 40R20514 AS IN DR107229 ; S/T EASE PT 15, PL 40R18818 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229 ; S/T EASE PT 4, PL 40R18818 IN FAVOUR PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229 ; S/T EASE PT 12, PL 40R18818 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229 ; S/T EASE PT 13, PL 40R18818 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229 ; S/T EASE PTS 20, 21 & 22, PL 40R20514 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229 ; S/T EASE PTS 5, 6 & 18, PL 40R20514 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229 ; S/T EASE PT 17, PL 40R20514 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229 ; S/T EASE PT 19, PL 40R20514 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229 ; S/T EASE PTS 23 & 24, PL 40R20514 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229 ; S/T EASE PT 3, PL 40R20514 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229 ; S/T EASE PTS 5, 8 & 9, PL 40R20514 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229; S/T EASE PTS 14 AND 15 PLAN 40R28269 AND PT 17 PL 40R28277 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229; T/W ROW PT 2, PL 40R20513 IN FAVOUR OF PT 9, PL 40R18818 & PT 1, PL 40R20514 AS IN DR107229; TOGETHER WITH AN EASEMENT AS IN DR1184508; TOGETHER WITH AN EASEMENT AS IN DR1184509; MUNICIPALITY OF CLARINGTON, being all of the lands identified by PIN 26606-0367 (LT) registered in the Land Registry Office for the Land Titles Division of Durham (No. 40).

2. RDAL BTN LTS 24 & 25 CON BROKEN FRONT DARLINGTON CLOSED BY BYLAW N90910, PT LT 23 CON BROKEN FRONT DARLINGTON & PT LT 24 CON BROKEN FRONT DARLINGTON PT 6, 10R94; PT LT 21 CON BROKEN FRONT DARLINGTON & PT LT 22 CON BROKEN FRONT DARLINGTON PTS 1 & 2, 10R342; PT LT 19 CON BROKEN FRONT DARLINGTON & PT LT 20 CON BROKEN FRONT DARLINGTON PT 4, 10R342; PT LT 18 CON BROKEN FRONT DARLINGTON PT 6, 10R342; RDAL BTN LTS 22 & 23 CON BROKEN FRONT DARLINGTON CLOSED BY BYLAW N90910 PT 5, 10R553; RDAL BTN LTS 20 & 21 CON BROKEN FRONT DARLINGTON CLOSED BY BYLAW N90910 PT 3, 10R342; RDAL BTN LTS 18 & 19 CON BROKEN FRONT DARLINGTON CLOSED BY BYLAW N90910 PTS 5 & 9, 10R342; FIRST AV PL 97 DARLINGTON, SECOND AV PL 97 DARLINGTON, THIRD AV PL 97 DARLINGTON & FOURTH AV PL 97 DARLINGTON CLOSED BY BYLAW N90910; LT 1534 PL 97 DARLINGTON; LT 1535 PL 97 DARLINGTON; LT 1536 PL 97 DARLINGTON; LT 1537 PL 97 DARLINGTON; LT 1538 PL 97 DARLINGTON; LT 1539 PL 97 DARLINGTON; LT 1540 PL 97 DARLINGTON; LT 1541 PL 97 DARLINGTON; LT 1542 PL 97 DARLINGTON; LT 1543 PL 97 DARLINGTON; LT 1544 PL 97 DARLINGTON; LT 1545 PL 97 DARLINGTON; LT 1546 PL 97 DARLINGTON; LT 1547 PL 97 DARLINGTON; LT 1548 PL 97 DARLINGTON; LT 1549 PL 97 DARLINGTON; LT 1550 PL 97 DARLINGTON; LT 1551 PL 97 DARLINGTON; LT 1552 PL 97 DARLINGTON; LT 1553 PL 97 DARLINGTON; LT 1554 PL 97 DARLINGTON; LT 1555 PL 97 DARLINGTON; LT 1556 PL 97 DARLINGTON; LT 1557 PL 97 DARLINGTON; LT 1558 PL 97 DARLINGTON; LT 1559 PL 97 DARLINGTON; LT 1560 PL 97 DARLINGTON; LT 1561 PL 97 DARLINGTON; LT 1562 PL 97 DARLINGTON; LT 1563 PL 97 DARLINGTON; LT 1564 PL 97 DARLINGTON; LT 1565 PL 97 DARLINGTON; LT 1566 PL 97 DARLINGTON; LT 1567 PL 97 DARLINGTON; LT 1568 PL 97 DARLINGTON; LT 1569 PL 97 DARLINGTON; LT 1570 PL 97 DARLINGTON; LT 1571 PL 97 DARLINGTON; LT 1572 PL 97 DARLINGTON; LT 1573 PL 97 DARLINGTON; LT 1574 PL 97 DARLINGTON; LT 1575 PL 97 DARLINGTON; LT 1576 PL 97 DARLINGTON; LT 1577 PL 97 DARLINGTON; LT 1578 PL 97 DARLINGTON; LT 1579 PL 97 DARLINGTON; LT 1580 PL 97 DARLINGTON; LT 1581 PL 97 DARLINGTON; LT 1582 PL 97 DARLINGTON; LT 1583 PL 97 DARLINGTON; LT 1584 PL 97 DARLINGTON; LT 1585 PL 97 DARLINGTON; LT 1586 PL 97 DARLINGTON; LT 1587 PL 97 DARLINGTON; LT 1588 PL 97 DARLINGTON; LT 1589 PL 97 DARLINGTON; LT 1590 PL 97 DARLINGTON; LT 1591 PL 97 DARLINGTON; LT 1592 PL 97 DARLINGTON; LT 1593 PL 97 DARLINGTON; LT 1594 PL 97 DARLINGTON; LT 1595 PL 97 DARLINGTON; LT 1596 PL 97 DARLINGTON; * LT 1629 PL 97 DARLINGTON; LT 1630 PL 97 DARLINGTON; LT 1631 PL 97 DARLINGTON; LT 1632 PL 97 DARLINGTON; LT 1633 PL 97 DARLINGTON; LT 1634 PL 97 DARLINGTON; LT 1635 PL 97 DARLINGTON; LT 1636 PL 97 DARLINGTON; LT 1637 PL 97 DARLINGTON; LT 1638 PL 97 DARLINGTON; LT 1639 PL 97 DARLINGTON; LT 1640 PL 97 DARLINGTON; LT 1641 PL 97 DARLINGTON; LT 1642 PL 97 DARLINGTON; LT 1643 PL 97 DARLINGTON; LT 1644 PL 97 DARLINGTON; LT 1645 PL 97 DARLINGTON; LT 1646 PL 97 DARLINGTON; LT 1647 PL 97 DARLINGTON; LT 1648 PL 97 DARLINGTON; LT 1649 PL 97 DARLINGTON; LT 1650 PL 97 DARLINGTON; LT 1651 PL 97

DARLINGTON; LT 1652 PL 97 DARLINGTON; LT 1653 PL 97 DARLINGTON; LT 1654 PL 97 DARLINGTON; LT 1655 PL 97 DARLINGTON; LT 1656 PL 97 DARLINGTON; LT 1657 PL 97 DARLINGTON; LT 1658 PL 97 DARLINGTON; LT 1659 PL 97 DARLINGTON; LT 1660 PL 97 DARLINGTON; LT 1661 PL 97 DARLINGTON; LT 1662 PL 97 DARLINGTON; LT 1663 PL 97 DARLINGTON; LT 1664 PL 97 DARLINGTON; LT 1665 PL 97 DARLINGTON; LT 1666 PL 97 DARLINGTON; LT 1667 PL 97 DARLINGTON; LT 1668 PL 97 DARLINGTON; LT 1669 PL 97 DARLINGTON; LT 1670 PL 97 DARLINGTON; LT 1671 PL 97 DARLINGTON; LT 1672 PL 97 DARLINGTON; LT 1673 PL 97 DARLINGTON; LT 1674 PL 97 DARLINGTON; LT 1675 PL 97 DARLINGTON; LT 1676 PL 97 DARLINGTON; LT 1677 PL 97 DARLINGTON; LT 1678 PL 97 DARLINGTON; LT 1679 PL 97 DARLINGTON; LT 1680 PL 97 DARLINGTON; LT 1681 PL 97 DARLINGTON; LT 1682 PL 97 DARLINGTON; LT 1683 PL 97 DARLINGTON; LT 1684 PL 97 DARLINGTON; LT 1685 PL 97 DARLINGTON; LT 1686 PL 97 DARLINGTON; LT 1687 PL 97 DARLINGTON; LT 1688 PL 97 DARLINGTON; LT 1689 PL 97 DARLINGTON; LT 1690 PL 97 DARLINGTON; LT 1691 PL 97 DARLINGTON; LT 1692 PL 97 DARLINGTON; LT 1693 PL 97 DARLINGTON; LT 1694 PL 97 DARLINGTON; LT 1695 PL 97 DARLINGTON; LT 1696 PL 97 DARLINGTON; LT 1697 PL 97 DARLINGTON; LT 1698 PL 97 DARLINGTON; LT 1699 PL 97 DARLINGTON; LT 1700 PL 97 DARLINGTON; LT 1701 PL 97 DARLINGTON; LT 1702 PL 97 DARLINGTON; LT 1703 PL 97 DARLINGTON; LT 1704 PL 97 DARLINGTON; LT 1705 PL 97 DARLINGTON; LT 1706 PL 97 DARLINGTON; LT 1707 PL 97 DARLINGTON; LT 1708 PL 97 DARLINGTON; LT 1709 PL 97 DARLINGTON; LT 1710 PL 97 DARLINGTON; LT 1711 PL 97 DARLINGTON; LT 1712 PL 97 DARLINGTON; LT 1713 PL 97 DARLINGTON; LT 1714 PL 97 DARLINGTON; LT 1715 PL 97 DARLINGTON; LT 1716 PL 97 DARLINGTON; LT 1717 PL 97 DARLINGTON; LT 1718 PL 97 DARLINGTON; LT 1719 PL 97 DARLINGTON; LT 1720 PL 97 DARLINGTON; LT 1721 PL 97 DARLINGTON; LT 1722 PL 97 DARLINGTON; LT 1723 PL 97 DARLINGTON; LT 1724 PL 97 DARLINGTON; LT 1725 PL 97 DARLINGTON; LT 1726 PL 97 DARLINGTON; LT 1727 PL 97 DARLINGTON; LT 1728 PL 97 DARLINGTON; LT 1729 PL 97 DARLINGTON; LT 1730 PL 97 DARLINGTON; LT 1731 PL 97 DARLINGTON; LT 1732 PL 97 DARLINGTON; LT 1733 PL 97 DARLINGTON; LT 1734 PL 97 DARLINGTON; LT 1735 PL 97 DARLINGTON; LT 1736 PL 97 DARLINGTON; LT 1737 PL 97 DARLINGTON; LT 1738 PL 97 DARLINGTON; LT 1739 PL 97 DARLINGTON; LT 1740 PL 97 DARLINGTON; LT 1741 PL 97 DARLINGTON; *LTS 1597 TO 1628 INCL, PL 97 DARLINGTON* ; CLARINGTON. *AMENDED 2000 08 24 BY T.CUTLER S/T EASE PTS 1 & 2, PL 40R21513 AS IN DR107221; S/T EASE PT 2, PL 40R20513 AS IN DR107229; TOGETHER WITH AN EASEMENT AS IN DR1184508; TOGETHER WITH AN EASEMENT AS IN DR1184509, being all of the lands identified by PIN 26606-0134 (LT) registered in the Land Registry Office for the Land Titles Division of Durham (No. 40).

O. Reg. 739/21, s. 6; O. Reg. 557/22, s. 5.

Français

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Ontario Energy Board Act, 1998

S.O. 1998, CHAPTER 15
Schedule B

Consolidation Period: From June 5, 2025 to the e-Laws currency date.

Last amendment: 2025, c. 4, Sched. 6.

Payments to prescribed generator

78.1 (1) The IESO shall make payments to a generator prescribed by the regulations with respect to output that is generated by a unit at a generation facility prescribed by the regulations. 2014, c. 7, Sched. 23, s. 7.

Payment amount

(2) Each payment referred to in subsection (1) shall be the amount determined in accordance with the order of the Board then in effect. 2014, c. 7, Sched. 23, s. 7.

Same, limitation re Ontario Power Generation Inc.

(3) The determination of a payment to Ontario Power Generation Inc. under this section shall not include any consideration of amounts related to activities of Ontario Power Generation Inc. carried out in relation to the *Ontario Fair Hydro Plan Act, 2017*. 2017, c. 16, Sched. 1, s. 44 (3).

Same

(3.1) The amounts referred to in subsection (3) include, without limitation, the following:

1. Amounts related to the appointment of Ontario Power Generation Inc. as the Financial Services Manager under the *Ontario Fair Hydro Plan Act, 2017*.
2. Amounts related to the charging of fees for performing duties as the Financial Services Manager.
3. Amounts related to exercising the powers and performing the duties of the Financial Services Manager.
4. Amounts related to the consolidation of the assets and liabilities for accounting purposes of the Fair Hydro Trust within the meaning of the *Ontario Fair Hydro Plan Act, 2017*. 2017, c. 16, Sched. 1, s. 44 (3); 2019, c. 6, Sched. 3, s. 12 (3).

Same

(3.2) A payment to Ontario Power Generation Inc. under this section shall not include any amounts that may be specified by the regulations relating to its activities under Part II.1 of the *Electricity Act, 1998*. 2022, c. 23, Sched. 1, s. 5.

Board orders

(4) The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment. 2004, c. 23, Sched. B, s. 15.

Fixing other prices

(5) The Board may fix such other payment amounts as it finds to be just and reasonable,

(a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; or

(b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Burden of proof

(6) Subject to subsection (7), the burden of proof is on the applicant in an application made under this section. 2004, c. 23, Sched. B, s. 15.

Order

(7) If the Board on its own motion or at the request of the Minister commences a proceeding to determine whether an amount that the Board may approve or fix under this section is just and reasonable,

(a) the burden of establishing that the amount is just and reasonable is on the generator; and

(b) the Board shall make an order approving or fixing an amount that is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Application

(8) Subsections (4), (5) and (7) apply only on and after the day prescribed by the regulations for the purposes of subsection (2). 2004, c. 23, Sched. B, s. 15.

Section Amendments with date in force (d/m/y)

2004, c. 23, Sched. B, s. 15 - 01/01/2005

2014, c. 7, Sched. 23, s. 7 - 01/01/2015

2017, c. 16, Sched. 1, s. 44 (3) - 01/06/2017

2019, c. 6, Sched. 3, s. 12 (3) - 01/11/2019

2022, c. 23, Sched. 1, s. 5 - 15/03/2023

Ontario

Electricity Generation Licence

EG-2023-0231

Ontario Power Generation Inc.

Valid Until

October 2, 2043

Brian Hewson
Vice President, Consumer Protection & Industry Performance
Ontario Energy Board
Date of Issuance: October 3, 2023
Date of Amendment: August 28, 2025

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
27th. Floor
Toronto, ON M4P 1E4

Commission de l'énergie de l'Ontario
C.P. 2319
2300, rue Yonge
27e étage
Toronto ON M4P 1E4

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PART 1 GENERAL CONDITIONS

1 Definitions

In this Licence:

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**generation facility**" means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system and includes any structures, equipment or other things used for that purpose;

"**Licensee**" means Ontario Power Generation Inc.;

"**regulation**" means a regulation made under the Act or the Electricity Act;

2 Interpretation

2.1 In this Licence words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of this Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this Licence where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens. Where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this licence:

a) to generate electricity or provide ancillary services for sale through the IESO-administered markets or directly to another person subject to the conditions set out in this Licence. This Licence authorizes the Licensee only in respect of those facilities set out in Schedule 1;

b) to purchase electricity or ancillary services in the IESO-administered markets or directly from a generator subject to the conditions set out in this Licence; and

c) to sell electricity or ancillary services through the IESO-administered markets or directly to another person, other than a consumer, subject to the conditions set out in this Licence.

3.2 The Licensee is authorized to conduct business in the name under which this Licence is issued, or any trade name(s) listed in Schedule 2.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act, and regulations under these acts, except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Maintain System Integrity

5.1 Where the IESO has identified, pursuant to the conditions of its licence and the Market Rules, that it is necessary for purposes of maintaining the reliability and security of the IESO-controlled grid, for the Licensee to provide energy or ancillary services, the IESO may require the Licensee to enter into an agreement for the supply of energy or such services.

5.2 Where an agreement is entered into in accordance with paragraph 5.1, it shall comply with the applicable provisions of the Market Rules or such other conditions as the Board may consider reasonable. The agreement shall be subject to approval by the Board prior to its implementation. Unresolved disputes relating to the terms of the Agreement, the interpretation of the Agreement, or amendment of the Agreement, may be determined by the Board.

6 Restrictions on Certain Business Activities

6.1 Neither the Licensee, nor an affiliate of the Licensee shall acquire an interest in a transmission or distribution system in Ontario, construct a transmission or distribution system in Ontario or purchase shares of a corporation that owns a transmission or distribution system in Ontario except in accordance with section 81 of the Act.

7 Provision of Information to the Board

7.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

7.2 Without limiting the generality of paragraph 7.1 the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee, as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

8 Term of Licence

8.1 This Licence shall take effect on October 3, 2023 and expire on October 2, 2043. The term of this Licence may be extended by the Board.

9 Fees and Assessments

9.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

10 Communication

10.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

10.2 All official communication relating to this Licence shall be in writing.

10.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; or

c) when received by facsimile transmission by the addressee, according to the sender=s transmission report.

11 Copies of the Licence

11.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

PART 2 PRICE CAP AND REBATE

1 Definitions and Interpretation

In Parts 2 through 5 inclusive of these Licence Conditions:

"**Average Price**" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by summing the product of the Hourly Price multiplied by the Contract Weight for all hours of that Settlement Period;

"**Changes in Law**" means changes in law (including without limitation environmental laws, laws affecting OPGI's generation facilities, tax laws and the general laws affecting the regulation of electricity in Ontario), but excluding provincial tax laws and, for greater certainty, excluding changes in licence conditions and market rules;

"**Contract Required Quantity**" or "CRQ" means the quantity of energy upon which any Rebate is determined, in respect of a Settlement Period, as set forth in the Model Output Data and as may be modified pursuant hereto. Subject to such adjustments, the CRQ will equal the sum of all Hourly Quantities for all hours in a Settlement Period;

"**Contract Weight**" or "CW_h" means the weighting for each hour in a Settlement Period, h, that is used to calculate the Average Price. For any particular hour, the Contract Weight equals the Hourly Quantity for that hour divided by the CRQ for that Settlement Period;

"**Effective Control**" in respect of output means control over the timing, quantity and bidding into the Ontario market of such output;

"***Force Majeure Adjustment***" or "FMA" means a reduction in the Rebate as a result of a *Force Majeure* Event;

"***Force Majeure* Event**" means an event defined in clause 2(c)(ii) of Part 2 below;

"***Force Majeure* Replacement Cost**" or "$FMRC_h$" means, for any particular hour in a Settlement Period, h, the predetermined net incremental replacement cost for each OPGI generation unit, as set forth in the Model Output Data that is used in determining the Force Majeure Adjustment, and as may be modified pursuant hereto. $FMRC_h$ may be constant in the Model Output Data over the hours in a month or other period;

"**Hourly Quantity**" or "Q_h" means, for any particular hour in a Settlement Period, h, the quantity of energy upon which the Contract Weight is established, as set forth in the Model Output Data. The sum of the Hourly Quantities for all hours in a Settlement Period equals the CRQ for that Settlement Period;

"**Hourly Price**" or "P_h" means, for any particular hour in a Settlement Period, h, the unconstrained spot price for energy for that hour expressed in a price in $ per MWh, as determined by the IESO pursuant to its market rules;

"**Hourly Reserve Capacity Price**" is the hourly market clearing price of reserve capacity;

"**Hourly Unit Quantity**," or "q^i_h" means, for any particular hour in a Settlement Period, h, the hourly quantity of energy associated with a particular OPGI generation unit, i, upon which the Hourly Quantity is established, as set forth in the Model Output Data. The sum of all Hourly Unit Quantities for all OPGI generation units in respect of an hour equals the Hourly Quantity for that hour;

"**Locational Spot Price**" means, for any particular hour in a Settlement Period, h, and any particular OPGI generation unit, the spot price for energy at such generation unit's interconnection, which will only apply if location-based marginal pricing is developed in Ontario;

"**Model Output Data**" means the data filed with the Board. The Model Output Data contains data, some of which is confidential, derived from a production cost model of the electricity market in Ontario and neighbouring regions under the assumption that OPGI is assumed to bid its generation units in a manner that achieves an average sales price of $ 38/MWh. The resulting CRQ, Q_h, and q^i_h data reflects 90 per cent of OPGI's predicted sales to Ontario customers;

"**OPGI**" means Ontario Power Generation Inc.

"**Potential *Force Majeure* Event**" means an event defined in clause 2(c)(i) of Part 2 below;

"**Price Cap**" or "CAP" means $38/MWh, which is the threshold used in calculating the Rebate;

"**Price Spike Adjustment**" or "PSA" means the reduction in the Rebate as a result of qualifying price spikes, as calculated pursuant hereto;

"**Prime Rate**" means the variable annual rate of interest, calculated on the basis of a calendar year, announced from time to time by the IESO's then principal Canadian banker as the reference rate of interest (commonly known as its prime rate) then in effect and used by such bank for determining interest rates on Canadian dollar denominated commercial loans made by it in Canada to customers of varying degrees of credit-worthiness;

"**Rebate" or "R**" means the amount OPGI must pay the IESO as a consequence of the Average Price in any Settlement Period exceeding the Price Cap, less any applicable adjustments;

"**Rebate Carryforward Adjustment**" or "RCA" means the adjustment in which negative Rebates from a Settlement Period are used to offset Rebates in subsequent Settlement Periods;

"**Reserve Capacity Ratio**" is a number greater than 1, such as 1.2, that is set by the IESO for the purposes of multiplying by the hourly demand to determine the reserve capacity target in such hour;

"**Settlement Period**" means each time period over which OPGI's compliance with the Price Cap shall be measured, which shall be over a 12 month period, except that (1) the first Settlement Period shall commence on the opening of the competitive electricity market and shall consist of the first full 12 calendar months plus the days, if any, in the first partial month; and (2) the last Settlement Period shall end on the termination of the provisions of Part 2, and therefore could be less than 12 full calendar months; and

"**Tier 1**" capacity means all nuclear and hydroelectric generation in Ontario and "**Tier 2**" capacity means that portion of Ontario's generation capacity, including inter-tie capacity and demand-side bidding, that is not part of Tier 1 capacity. For such purposes, generation capacity shall be based upon the maximum continuous rating of a unit, inter-tie capacity shall be based on the average of summer and winter season Ontario transfer capacity, and demand-side bidding shall be based on the sum of the dispatchable and interruptible loads, all expressed in MW.

All dollar amounts referred to are expressed in Canadian dollars.

2 Determination of Rebate

OPGI shall pay a Rebate to the IESO in respect of each Settlement Period in which the Average Price (AP) exceeds the Price Cap (CAP). The amount of the Rebate shall be determined in accordance with the following formula:

R = [(AP - CAP) * CRQ] - (RCA + PSA + FMA)

If the calculated Rebate in respect of any Settlement Period is a negative number, then there shall be no Rebate, and the Rebate Carryforward Adjustment shall be changed as described herein.

(a) *Rebate Carryforward Adjustment*

Initially, the Rebate Carryforward Adjustment ("RCA") shall be zero. In any Settlement Period in respect of which the calculated Rebate is negative, the absolute value of that amount shall be the Rebate Carryforward Adjustment for the purposes of the next Settlement Period.

(b) *Price Spike Adjustment*

A Price Spike Adjustment (PSA) shall be calculated for all hours in a Settlement Period in which both (1) the Hourly Price (P_h) exceeds $125/MWh, and (2) OPGI's Generation for that hour is less

than the Hourly Quantity (Q_h). The PSA for a Settlement Period shall equal the sum of the adjustments for each applicable hour, which shall be calculated pursuant to the following formula:

PSA = (P_h - $125/MWh) * ($Q_h$ – OPGI's Generation for that hour)

where OPGI's Generation for that hour = OPGI's energy generated from all sources in Ontario (metered as per IESO market rules) the output of which is Effectively Controlled by OPGI and which was included as OPGI energy generated in the Model Output Data, and includes the current power purchase agreement with Manitoba Hydro.

(c) *Force Majeure* Adjustment

(i) Potential *Force Majeure* Event

A Potential *Force Majeure* Event is any event consisting of any of the following conditions or events that results in the loss or failure of, or the inability to operate, in whole or in part, one or more generation units in Ontario the output of which is Effectively Controlled by OPGI and that, in each case, is beyond the reasonable control of OPGI and which is not a result of OPGI's failure to comply with pre-existing laws or licence conditions or market rules or to reasonably maintain or to use its best efforts to promptly repair any generation unit or units:

(A) acts of war, revolution, riot, sabotage, occupation or vandalism;

(B) earthquakes, tornadoes or severe storms;

(C) other acts of God;

(D) local, regional or national states of emergency;

(E) strikes or other labour disputes;

(F) other failure or damage to an OPGI generating facility, including failure or damage caused by construction defects, fire, or damage to necessary equipment and which is not a result of negligence in the maintenance or repair thereof;

(G) interruptions in the supply of fuel or other essential supplies (excluding variations in water supplies in the case of hydroelectric generation units);

(H) failure of transmission or distribution facilities in Ontario;

(I) other system emergencies in Ontario; and

(J) Changes in Law.

(ii) Definition of *Force Majeure* Event

A *Force Majeure* Event is either an Isolated *Force Majeure* Event or a Cumulative *Force Majeure* Event.

An Isolated *Force Majeure* Event is that portion of any Potential *Force Majeure* Event that occurs after the Potential *Force Majeure* Event has caused a reduction in the energy actually generated by the applicable units greater than

250,000 MWh from the sum of such units' Hourly Unit Quantities during the effectiveness of such Potential *Force Majeure* Event.

A Cumulative *Force Majeure* Event occurs in a Settlement Period when the cumulative reduction in that Settlement Period of energy actually generated by affected generation units in Ontario the output of which is Effectively Controlled by OPGI caused by Potential *Force Majeure* Events exceeds 500,000 MWh when compared to the sum of such affected units' Hourly Unit Quantities during the effectiveness of such Potential *Force Majeure* Events. OPGI will, where applicable, designate within 15 days following the end of the applicable Settlement Period that portion of Potential *Force Majeure* Events that is in excess of 500,000 MWh and that qualifies as a Cumulative *Force Majeure* Event.

A Potential *Force Majeure* Event, or a portion of a Potential *Force Majeure* Event, that qualifies as both an Isolated *Force Majeure* Event or a Cumulative *Force Majeure* Event may at the discretion of OPGI within 15 days following the end of the applicable Settlement Period be designated as either type of *Force Majeure* Event, but not as both, and, for greater certainty, a Potential Force Majeure Event designated as one type of *Force Majeure* Event by OPGI shall not be treated for purposes of determining whether the other type of *Force Majeure* Event has occurred.

(iii) *Force Majeure* Adjustment

A Force Majeure Adjustment (FMA) in respect of any Settlement Period shall be equal to the sum, for all generation units the output of which is Effectively Controlled by OPGI subject to *Force Majeure* Events, of the *Force Majeure* Replacement Cost ($FMRC_h$) in respect of each applicable unit for each hour during the effectiveness of each *Force Majeure* Event in respect of such unit during the Settlement Period, less any insurance or other recovery in respect of such loss or deemed loss.

The *Force Majeure* Adjustment in respect of any Settlement Period for each generation unit the output of which is Effectively Controlled by OPGI whose generation is reduced as a consequence of a *Force Majeure* Event shall be calculated pursuant to the following formula, prior to any recovery adjustment:

$$\sum_{h} [q^{i}_{h} * FMRCh * ((Capacity - Reduced\ Capacity_{h})/Capacity)]$$

where:
Capacity = the maximum continuous rating of the unit at the time of the *Force Majeure* Event (at normal head for hydroelectric generation units);
and
$Reduced\ Capacity_h$ = the reduced capacity in an hour of the unit as a consequence of and during the effectiveness of the *Force Majeure* Event.

(iv) Adjustment to *Force Majeure* Replacement Cost

In the event that over 2,000 MW of OPGI generating capacity the output of which is Effectively Controlled by OPGI qualifies for a particular *Force Majeure* Event, OPGI shall have the right to petition the Board to increase the amount of the *Force Majeure* Replacement Cost in respect of one or more affected unit(s) in the applicable hours, which petition shall be granted if OPGI can demonstrate to the Board's satisfaction higher incremental replacement costs (net of any variable

costs avoided as a consequence of the *Force Majeure* Event) than those set forth in the Model Output Data.

(v) Notice

OPGI shall promptly notify the IESO of any *Force Majeure* Event claimed by OPGI and shall provide the IESO with all information reasonably required to verify the *Force Majeure* Event and to calculate the *Force Majeure* Adjustment.

3 Conduct of OPGI

3.1 OPGI may engage in unilateral actions to attempt to maintain Hourly prices at levels that will result in the Average Price for a Settlement Period equaling the Price Cap, plus all adjustments provided for in Part 2, Section 2 above. In the event that unilateral actions taken by OPGI cause the Average Price to exceed such a level, the sole remedy shall be for OPGI to pay the Rebate as provided for in paragraph 2 of Part 2 above.

4 Reduction to CRQ and Q_h Upon Decontrol

(a) *Unadjusted Reductions*

Except as may be provided in (b) below, in the event that OPGI completes the transfer of Effective Control over the output of a generation unit, as determined by the Board under Part 3, then Q_h for each hour in respect of the current and any subsequent Settlement Period shall be reduced by 110 percent of the q^i_h of the transferred unit for each hour subsequent to the completion of the transfer. As a result, the CRQ in respect of each applicable Settlement Period shall be reduced by these reductions in Q_h.

(b) *Adjustment Necessitated by Environmental Laws*

In the event that OPGI transfers Effective Control over the output of a generation unit and the transferee, at the date of completion of the transfer, does not have and cannot reasonably obtain sufficient environmental emission permits or other environmental authorizations ("emission permits"), in respect of the applicable hours in the period commencing following the completion of the transfer of Effective Control (the "applicable hours"), to enable the unit's potential output during the applicable hours (the "transferred permitted output") to meet or exceed 110 percent times the sum for the applicable hours of the q^i_h of such unit (the "transferred output"), whether as the result of a change in environmental laws or otherwise, then:

(i) any adjustment to Q_h and CRQ otherwise provided for in (a) above will reduced by the proportion that the transferred permitted output is of the transferred output, subject to (ii) below;

(ii) in circumstances where OPGI's remaining emission permits following the transfer of Effective Control are not sufficient to enable its remaining output during the applicable hours (the "remaining permitted output") to meet or exceed 110 percent times the sum for the applicable hours of the q^i_h's of its remaining units, (the "remaining output"), then, in lieu of the adjustment provided for in (i) above, any adjustment to Q_h and CRQ otherwise provided for in (a) above will be multiplied by the result of the following formula, which if greater than 1.0 shall be deemed to be equal to 1.0:

(transferred permitted output/transferred output)/
(remaining permitted output/remaining output); and

(iii) where the transferee's emission permits are affected by more than one substance, then the resulting adjustment to Q_h and CRQ otherwise provided for in (i) or (ii) above will be that which operates to constrain the transferee's output.

5 Administration of Rebate

5.1 OPGI shall enter into and comply with a settlement agreement with the IESO consistent with the document attached as Schedule A and B to this licence.

6 Capacity Reserve Market

6.1 In the event that a capacity reserve market is developed in Ontario at any time while the provisions of Part 2 are in effect, then:

(a) the following definition of "Average Price" or "AP" shall be used in lieu of the definition provided for in paragraph 1 of Part 2 above:

"Average Price" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by using the following formula:

AP=

$$\sum_{h} [CW_h * [P_h + (\text{Hourly Reserve Capacity Price} * \text{Reserve Capacity Ratio})]]$$

(b) the Price Spike Adjustment shall be calculated according to the following formula in lieu of the formula provided for in paragraph 2(b) of Part 2 above:

PSA = [(P_h + Hourly Reserve Capacity Price * Reserve Capacity Ratio) - $125/MWh] * ($Q_h$ – OPGI's Generation for that hour);

(c) OPGI may apply to the Board for adjustments to (a) or (b) above if necessary or desirable depending upon the precise nature of the capacity reserve market introduced.

7 Location-Based Marginal Pricing

In the event that location-based marginal pricing is developed in Ontario at any time while the provisions of Part 2 are in effect, then:

(a) the following definition of "Average Price" or "AP" shall be used in lieu of the definition provided for in paragraph 1 of Part 2 above:

"Average Price" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by using the following formula:

AP=

$$\sum_{h,i} (\text{Locational Spot Price} * q^i_h)/CRQ$$

(b) the Hourly Price, or P_h, for purposes of determining if a price spike has occurred and in order to calculate the Price Spike Adjustment in each applicable hour, shall be the

average price of energy OPGI sells into the IESO spot market in that hour, which average price shall be determined by dividing OPGI's hourly spot market revenue in $ by the quantity (calculated in MWh) of OPGI's spot market sales; and

(c) OPGI may apply to the Board for adjustments to (a) or (b) above if necessary or desirable depending upon the precise nature of the location-based marginal pricing introduced.

8 Capacity Reserve Market and Location-Based Marginal Pricing

In the event that both a capacity reserve market and location-based marginal pricing are developed in Ontario at any time while the provisions of Part 2 are in effect, then:

(a) the following definition of "Average Price" or "AP" shall be used in lieu of the definitions provided for in paragraphs 1, 6 or 7 of Part 2 above:

"Average Price" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by using the following formula:

$$AP = \sum_{h}[CW_h * (\text{Hourly Reserve Capacity Price} * \text{Reserve Capacity Ratio})]$$

$$+ \sum_{h,i} (\text{Locational Spot Price} * q^i_h)/CRQ$$

(b) the Price Spike Adjustment shall be calculated according to the following formula in lieu of the formula provided for in paragraphs 2(b) or 6 of Part 2 above:

$$PSA = [(\text{Hourly Reserve Capacity Price} * \text{Reserve Capacity Ratio})$$

$$+ \sum_{i} ((\text{Locational Spot Price} * q^i_h)/Q_h) - \$125/MWh]$$

$$* (Q^h - \text{OPGI's Generation for that hour});$$

(c) OPGI may apply to the Board for adjustments to (a) or (b) above if necessary or desirable depending upon the precise nature of the capacity reserve market or location-based marginal pricing introduced.

9 Additional Adjustment for Changes in Law

If one or more Changes in Law cause or are reasonably expected to cause a decrease in OPGI's net annual income equal to or greater than $60,000,000, then, rather than treating such Changes in Law as a Force Majeure Event for purposes of paragraph 2 above, OPGI may apply to the Board for a variation in the CRQ, Rebate, and/or the Price Cap methodology in respect of the Settlement Period in which the Change in Law occurs and all subsequent Settlement Periods the Change in Law is reasonably expected to affect in order to ensure that OPGI is not materially adversely affected as a result, taking into account all Changes in Law and whether the net effect of these Changes in Law have benefited or are reasonably likely to benefit OPGI during the same time period or any prior or subsequent time period.

10 Termination of Part 2

Beginning April 1, 2005 the OPG rebate calculation will be determined by the formula set out in Schedule B - Additional Terms and Conditions of Settlement Agreement Between IESO & OPG as amended from time to time.

PART 3 TRANSFER OF EFFECTIVE CONTROL

[Part 3 is revoked, effective December 7, 2005]

PART 4 INBOUND TRANSMISSION RIGHTS AND IMPORT LIMITS

1 Definitions and Interpretation

In this Part 4, "season" means the winter period (the "winter season") from and including November 1 until and including April 30 of the following year or the summer period (the "summer season") from and including May 1 until and including October 31 of the same year, as applicable.

2 Inter-tie and Import Limits

(a) OPGI shall not import energy into Ontario in excess of the energy import limits set forth in (b) below. In no event shall a purchase from the IESO spot market in Ontario be construed as an import of energy into Ontario for such purposes.

(b) The energy import limits referred to in (a) above are:

(i) 7.24 TWh during the winter season (increased to 7.28 TWh in a leap year); and

(ii) 6.58 TWh during the summer season;

all of which figures shall be increased, at the in service date of new or upgraded inter-tie facilities, by 35 percent times the number of hours in a season multiplied by any applicable net increase in inter-tie capacity in Ontario as determined by the IESO from that in effect on the date of the opening of the competitive electricity market. For such purposes, inter-tie capacity shall be based on the Ontario transfer capacity in the applicable season.

(c) The foregoing provisions of paragraph 2 shall not be required to be complied with by OPGI with the IESO's consent in an emergency situation.

3 Export Limits

Unless otherwise provided herein, none of the provisions of Parts 2 through 5 shall limit OPGI's ability to export energy from Ontario.

PART 5 MARKET BASED ANCILLARY SERVICES

(Note: Market based ancillary services are currently comprised of Operating Reserves only, but the principles outlined herein suggest a framework that could be used for other market based ancillary services.)

Unless the IESO has determined, based on the number of independently controlled competing alternatives and other circumstances in its discretion, that a competitive market for any category of operating reserves (i.e. 10-minute and 30-minute) exists, OPGI shall be required to comply with the following requirements:

(a) subject to (a.1), the price to be offered by OPGI associated with each category of OPGI operating reserve services will not exceed a cap to be contained in an agreement to be negotiated between OPGI and the IESO, which cap will be designed, taking into account the relevant IESO market rules, to compensate OPGI for its actual cost of providing such operating reserve services, including additional operating and maintenance costs, additional fuel costs, additional opportunity costs associated with providing such operating reserve services from OPGI hydroelectric generation units, and a reasonable rate of return on incremental capital needed to provide such operating reserve services, and which agreement shall require OPGI to offer the maximum available amount of each category of operating reserve services, consistent with good utility practices, for each OPGI generation unit capable of providing such services;

(a.1) notwithstanding (a) above, save and except where the IESO has advised OPGI that specific units are required to offer in for reliability, OPGI may offer less than the maximum available amount of any category of operating reserve where this is necessary in order for OPGI to satisfy its obligations under, or to give effect to, any shareholder declaration or resolution of the Minister of Energy in effect at the relevant time relating to, or any Regulation made under the *Environmental Protection Act* (Ontario) relating to, carbon dioxide (CO_2) emissions arising from the use of coal at OPGI's coal-fired generation stations;

(b) subject to (a.1), in the event that the agreement referred to in (a) above cannot be reached, the terms of such agreement shall be determined through binding commercial arbitration by a mutually agreed independent arbitrator on agreed terms of arbitration;

(c) subject to (a.1), in the event that either OPGI or the IESO subsequently determines that the operation of the market is such that the intent of the agreement referred to in (a) or (b) above is materially frustrated, then OPGI and the IESO shall negotiate amendments (which may be retroactive) to the terms of such agreement with a view to correcting such situation and, in the event that they cannot agree on such amendments, the amendments, if any, shall be determined through binding commercial arbitration by a mutually agreed independent arbitrator on agreed terms of arbitration;

(d) subject to (a.1), OPGI shall comply with the terms of the agreement referred to in (a) or (b) above, as it may be amended under (c) above;

(e) subject to (a.1)**,** pending reaching an agreement, or pending the resolution of any dispute, the IESO may at any time set the price cap and terms on which OPGI must provide any category of operating reserve services, subject to later adjustment upon final agreement or final resolution of the dispute with interest at the Prime Rate, calculated and accrued daily; and

(f) subject to (a.1), if the IESO's market rules at any time are such that the market clearing price for a category of operating reserve services does not include both the offer price and the opportunity cost of the marginal unit providing the service, and the agreement referred to in (a) or (b) above has not taken such factors into account, then the agreement referred to in (a) or (b) above shall be considered to have been materially frustrated for purposes of (c) above.

PART 6 BRUCE DECONTROL RELATED CONDITIONS

1. The Licensee shall implement a Ring-Fence plan in accordance with the plans referred to in Section 8A of OPG's pre-filed evidence, and as detailed more fully in Interrogatory Responses I 6.5, and I 15.13 of RP-2002-0142, with the following exception:

    a) Only commercially sensitive information will be captured by the Ring-Fence plan. For clarity, this consists of Bruce Power outage information not already in the public domain and unit condition information only.

2. The Licensee shall conduct internal audits of the Ring-Fence plan every two calendar years.

3. The Licensee must provide to the Board every year a self-certification statement signed by both the Chief Executive Officer and the Senior Regulatory Officer or other Senior Officer of OPG that the Ring-Fence plan methodology is operational for the activities that remain ring-fenced.

4. OPG shall make Status Reports to the Board within 30 days of:

    a. Any additional agreements entered into with BP LP;

    b. Any amendments, replacements or extensions of existing agreements with BP LP; and

    c. Expired agreements under the Bruce Transaction.

5. Prior to May 1st of every other year of this licence (coincident with the years in which an internal audit is conducted), OPG shall submit an annual Confidential Audit Report to the Board. The report shall include:

    a. A review of the design, implementation, completeness and security of the Ring-Fence plan by OPG's internal audit group;

    b. A list of all the violations of the Ring-Fence plan with an explanation as to the type of violation, the employee's position and department or group, and whether the incident represents a repeat violation by a given employee;

    c. Recommendations regarding corrective action where the Ring-Fence plan has been violated;

    d. A list of the number of employees that have moved outside the Ring-Fence to a new position in OPG (whether the position is permanent or temporary) The Report shall identify the old position and department or group that was in the Ring-Fence plan, and the new position and department or group in which the employee now works.

6. Prior to December 31st of every other year of this licence (coincident with the years in which an internal audit is conducted), OPG shall submit an annual Public Audit Report to the Board for the public record. The report shall include the above findings from the Confidential Audit Report, however, the report shall be redacted to remove personal information and any other information that the Board agrees may be redacted under its confidential filing guidelines.

7. The Contract for Differences for Forced Outages agreement between OPG and BP LP shall not be renewed at its expiry on the second anniversary of Market Opening.

PART 7 RING-FENCING OF AFFILIATE MARKET FUNCTIONS

1. The Licensee shall not share employees that are directly involved in the offer to supply electricity or ancillary services into any of the IESO-administered markets with NV LP or any subsidiary of NV LP including Portlands Energy Centre L.P. and Brighton Beach Power L.P. This shall not preclude (i) the sharing between the Licensee and NV LP or a subsidiary of NV LP of employees in “shared corporate services” as defined in the Affiliate Relationships Code for Electricity Distributors and Transmitters, or (ii) employees of the Licensee from serving as a director of NV LP or a subsidiary of NV LP, provided that in both cases such employees are subject to the ring-fencing plan restrictions established in accordance with this Part 7.

2. The Licensee shall implement a ring-fencing plan to ensure that (i) no competitively sensitive information (“CSI”) pertaining to the Licensee is disclosed to NV LP or any subsidiary of NV LP, (ii) employees of the Licensee that are directly involved in the offer to supply electricity or ancillary services into any of the IESO-administered markets do not obtain or have access to CSI pertaining to NV LP or any subsidiary of NV LP, and (iii) no CSI pertaining to NV LP or a subsidiary of NV LP that may be in the possession of the Licensee is used by the Licensee for any purpose relating to the offer to supply electricity or ancillary services into any of the IESO-administered markets.

3. For the purpose of paragraph 2, CSI includes information about electricity bid and offer strategy, electricity offer prices and quantities, gas procurement strategies and outage plans. CSI does not include (i) historical data or information that is no longer competitively relevant, (ii) data or information that is in the public domain, or (iii) documents from which competitive information has been redacted, deleted, aggregated or otherwise dealt with in a manner that renders the document in question not commercially sensitive. For clarity, reference to a limited partnership in this Part 7 shall include its general partner(s).

4. Notwithstanding the requirements in paragraphs 2 and 3 of this Part 7, the Licensee shall not be prohibited from sharing CSI with NV LP's subsidiary Atura H2 LP to the extent the CSI consists of information related to forward-looking outage plans that are not in the public domain (a) where the outage plans are necessary for the connection, commissioning or testing of Atura H2 LP facilities associated with its hydrogen production facility known as the "Niagara Hydrogen Centre", or (b) where OPG requires the outage to perform work on units and associated facilities at its Sir Adam Beck II Generating Station that are directly involved in the supply and delivery of electricity to the Niagara Hydrogen Centre. This exemption shall expire on August 27, 2030.

PART 8 REQUIREMENT TO OFFER INTO IESO ADMINISTERED MARKETS

1. Subject to any applicable regulatory or safety requirements and the Agreement described in paragraph 2, the Licensee shall comply with the following condition (the Must-Offer Condition):

    a. the Licensee shall, at all times during any period that the Legacy Market Rules (as defined in the Market Rules) are in force, offer all available generating capacity into the IESO administered markets for Operating Reserve, the Day Ahead Commitment Process and real-time Energy; and

    b. the Licensee shall, at all times during any period that the Renewed Market Rules (as defined in the Market Rules) are in force, offer all available generating capacity into the IESO administered markets for Energy and Operating Reserve, including the Day-Ahead Market and the Real-Time Market.

2. The Licensee shall enter into an Agreement with the IESO for the purpose of assessing ongoing compliance with the Must-Offer Condition established in paragraph 1. The Agreement shall

include any necessary detail or description of the Must-Offer Condition, the criteria that will be used to assess whether the Licensee has complied with the condition, and the right for the IESO to audit the Licensee where the IESO identifies based on the criteria that the Licensee may not have complied with the condition. The Licensee shall file the Agreement for approval of the OEB. Once the Agreement is approved, any material changes to the Agreement shall be filed with the OEB for approval.

SCHEDULE A

TERMS AND CONDITIONS OF SETTLEMENT AGREEMENT BETWEEN IESO AND OPGI

For these purposes, terms with initial capitals not otherwise defined herein shall have the meanings ascribed thereto in paragraph 1 of Part 3 of the licence conditions of OPGI or the IESO's Market Rules, as applicable.

OPGI will be required to rebate annually to the IESO. As soon as practicable and preferably within 15 days following the final settlement of transactions which occurred during each Settlement Period, the IESO shall calculate the Rebate and notify OPGI of such calculated Rebate.

If OPGI agrees with the IESO's calculation then, within 30 days of being notified, OPGI will be required to pay such Rebate, if any, to the IESO. If OPGI does not agree with the IESO's calculation and the parties can agree within a further 30 days on a revised Rebate, then, within 30 days of so agreeing, OPGI will be required to pay the agreed revised Rebate, if any, to the IESO. If OPGI does not agree with the IESO's calculation and the parties cannot agree on a revised Rebate within such further 30 day period, then the matter shall be finally determined by arbitration by the Dispute Resolution Panel of the IESO, and, within 30 days of such final determination, OPGI will be required to pay the finally determined Rebate, if any, to the IESO. The initially calculated, agreed revised, or finally determined Rebate, as applicable, shall be the Rebate in respect of such Settlement Period for all purposes hereof. Unless the Rebate is paid within 30 days of the IESO notifying OPGI, interest at the Prime Rate, calculated and accrued daily, from such 30th day until the date of payment to the IESO will in all cases be added to (and based upon) the final Rebate owing.

Following payment of the Rebate by OPGI to the IESO, the IESO shall pay or apply the Rebate as follows:

(a) Where the Rebate is $10 million or more, exclusive of any amounts representing interest or GST, the IESO shall pay the Rebate, including GST and interest, to all persons who were Market Participants in Ontario during the Settlement Period and who pursuant to the Market Rules had attributed to them during the Settlement Period an allocated quantity of energy withdrawn at a Delivery Point (the "Ontario Payees"). The IESO shall pay the Rebate to Ontario Payees by the next IESO Payment Date for the real-time market following the end of the month in which the payment from OPGI is received and the IESO shall distribute payment of the Rebate to Ontario Payees in proportion to the allocated quantities of energy withdrawn at a Delivery Point which were attributed to each Ontario Payee during the Settlement Period. The IESO may, to the extent practicable, pay the Rebate to all or some Ontario Payees by applying a Rebate settlement credit to the Ontario Payees' applicable Settlement Statements; and

(b) Where the Rebate is less that $10 million, exclusive of any amounts representing interest or GST, the IESO shall retain and apply the Rebate, inclusive of any amounts representing interest or GST, to offset the IESO Administration Charge imposed on Market Participants in accordance with section 4.5, Chapter 9 of the Market Rules, during the period in which the first order of the OEB approving the IESO Administration Charge made,

(i) pursuant to subsection 19(2) of the Electricity Act, 1998, and

(ii) subsequent to the date on which payment of the Rebate is received by the IESO, is in effect.

Where paragraph (a) applies, if by the date upon which the IESO is required to pay the Rebate to Ontario Payees, the IESO cannot locate an Ontario Payee, or a successor or other representative of the said Ontario Payee to whom the IESO is permitted or required by law to pay the said

Ontario Payee's share of the Rebate, the IESO shall retain the said Ontario Payee's share of the Rebate for a period of 90 days from the date upon which the Rebate is otherwise payable to all other Ontario Payees, and during this period the IESO will make commercially reasonable efforts to locate and payout the applicable share of the Rebate to the said Ontario Payee or his successor or other legal representative. If the IESO is unable to locate the said Ontario Payee or his successor or other legal representative within this 90 day period, the IESO shall retain the said Ontario Payee's share of the Rebate and apply it to the IESO Administration Charge in accordance with paragraph (b), as set out herein.

Nothing shall preclude agreements that require the purchaser to return the rebate or any portion thereof to OPGI or any other party.

The Settlement Agreement may also include the following terms:

- Definitions and Interpretation
- Notice by OPGI to IESO of Payment and Non-Payment
- Appropriate limitations of liability
- IESO shall recover its reasonable rebate administration expenses through its fees
- Appropriate indemnification provisions
- IESO to act on its own behalf and as agent for Ontario Metered Market Participants entitled to rebates to the extent of their interests, and such Metered Market Participants are entitled, provided that they give a satisfactory funded indemnity to the IESO, to enforce, by arbitration, the Settlement Agreement directly against OPGI if desired, with reasonable assistance to be provided by IESO at their expense
- IESO may assign agreement to a qualified replacement upon approval of OEB. No other assignments without consent of other party and OEB
- IESO may subcontract any duties required of it
- Fund transfer instructions, which may be changed on notice to OPGI by IESO
- Arbitration clause with Dispute Resolution Panel as arbitrator
- Recipient registrants responsible for all taxes, if any
- Any interest earned on funds by IESO shall be paid to recipient registrants similarly to other funds
- IESO not to be viewed as in conflict in any respect as a result of its participation in the Settlement Agreement
- IESO may hold funds on deposit with a Canadian financial institution or in short-term obligations of the federal or Ontario government or any Canadian financial institution
- IESO may, but shall not be obliged to, retain and refrain from distributing any funds in the event of any dispute, and may seek advice from the Dispute Resolution Panel
- Termination of agreement when OPGI Rebate obligations terminate and all funds distributed or applied. OPGI/IESO indemnification obligations and third party enforcement rights to survive termination, former indefinitely and latter for 2 years only
- IESO may rely on any document which it believes to be genuine and on the advice of counsel, if it acts in good faith
- IESO not responsible for any non-payment by OPGI
- Binding on successors and permitted assigns
- Notice clause
- Only may be amended in writing
- Governed by the laws of Ontario
- Counterparts clause
- Further assurances clause

SCHEDULE B

ADDITIONAL TERMS AND CONDITIONS OF SETTLEMENT AGREEMENT BETWEEN IESO & OPG

The following sets out the procedure for calculating, allocating and passing through the Market Power Mitigation Agreement (MPMA) Rebate. Where there is a conflict between Schedule A in the Minister's Directive dated March 24, 1999, as amended or replaced by a subsequent Ministerial Directive dated February 25, 2003 which relates to Order-in-Council 654/2003 (dated March 19, 2003), and subsequent Orders-in-Council including Order-in-Council No. 843/2003 (dated April 2, 2003), Order-In-Council No. 207/2005 (dated February 16, 2005), Order-in-Council No. 1909/2005 (dated December 7, 2005), Order-in-Council No. 141/2006 (dated February 3rd, 2006), Order-in-Council No. 1062/2006 (dated May 17, 2006) and this Schedule B, then this Schedule B prevails.

For the First Settlement Period (May 1, 2002 to April 30, 2003)

1) The first MPMA Rebate is to be paid out for the 9-month period ending January 31, 2003. This is the amount, as calculated by the IESO and agreed to by OPG, that OPG is required to rebate for the nine month period, based on OPG's MPMA license conditions, less the interim payment already made by OPG of approximately $335 million and amounts relating to decontrol applications pending before the Ontario Energy Board. OPG is to pay this net amount to the IESO by May 9, 2003.

2) The second MPMA Rebate will cover the three-month period February 1, 2003 to April 30, 2003 inclusive. This is the amount, as calculated by the IESO and agreed to by OPG, that OPG is required to rebate for the three month period, based on OPG's license conditions, adjusted for any true-up required to ensure that the sum of the two rebates for the first settlement period, including the interim payment, is equal to OPG's full rebate requirements for the first Settlement Period under the OPG's MPMA license conditions. OPG is to pay this amount to the IESO by August 12, 2003.

3) The IESO will pay the pro rata share of the first MPMA Rebate and the second MPMA Rebate based on the allocated quantity of energy withdrawn during the applicable period by market participants who are receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act*, *1998* to the Ontario Electricity Financial Corporation.

4) The IESO will pay the pro rata share of the first MPMA Rebate and the second MPMA Rebate based on the allocated quantity of energy withdrawn during the applicable period by market participants who are not distributors and are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their MPMA rebate.

5) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the first MPMA Rebate and the second MPMA Rebate based on the share of energy withdrawn during the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* and by customers of retailers who have assigned all or a portion of their entitlement to an MPMA Rebate to that retailer. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the first MPMA Rebate or the second MPMA Rebate in accordance with this Schedule B, there shall be no opportunity to

correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

6) After making the payments set out in 3), 4), and 5), the IESO is to pay any remaining Rebate to the Ontario Electricity Financial Corporation to offset in whole or in part the cost of providing the fixed price of 4.3 cents per kilowatt hour to consumers who are eligible to receive, are receiving or have received the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*. Any amounts returned to the IESO by distributors in accordance with their license conditions shall be paid over to the Ontario Electricity Financial Corporation.

For the Settlement Periods (May 1, 2003 to January 31, 2005)

7) For each Settlement Period or partial Settlement Period from May 1, 2003 to January 31, 2005, OPG is to make quarterly MPMA Rebate payments to the IESO, consistent with OPG's MPMA license conditions, as calculated by the IESO and agreed to by OPG. The IESO and OPG may agree to appropriate true-up and carry forward mechanisms provided that these are consistent with forwarding the Rebate as soon as practicable.

8) For each Settlement Period or partial Settlement Period from May 1, 2003 to January 31, 2005 the MPMA rebate payments to market participants will be calculated and determined by the IESO as follows:

BPPR = [(WAP – CAP) x 0.5 x TAQEW]

Where:
"Business Protection Plan Rebate" or "BPPR" is the MPMA Rebate paid out to consumers who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*. The BPPR is to rebate half of the amount by which the weighted average commodity price of electricity exceeds 3.8 cents per kilowatt- hour.

"Weighted Average Price" or "WAP" is the average Hourly Ontario Electricity Price weighted by load over the Settlement Period as determined by the IESO.

"Total Allocated Quantity of Energy Withdrawn" or "TAQEW" is the total electricity withdrawn from the IESO-controlled grid for use in Ontario during the Settlement Period.

9) The IESO will make quarterly MPMA payments to market participants based on the applicable Settlement Period to the end of the previous quarter, and taking into account all prior quarterly MPMA payments made with respect to the applicable Settlement Period. The IESO will adjust the payment for the final quarter of each Settlement Period to ensure that the sum of the quarterly MPMA payments for the applicable Settlement Period does not exceed the BPPR entitlement for the Settlement Period. If there is an overpayment of quarterly payments over a Settlement Period based on the BPPR entitlement for that Settlement Period, any such overpayment can be carried over to successive Settlement Periods to be offset against future payments.

10) The IESO will pay the pro rata share of the BPPR based on the allocated quantity of energy withdrawn for the applicable period by market participants who are receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act*, *1998* to the Ontario Electricity Financial Corporation.

11) The IESO will pay the pro rata share of the BPPR based on the allocated quantity of energy withdrawn for the applicable period by market participants who are not distributors and are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*

directly to those market participants or their assignees that are market participants where the market participants have assigned their MPMA Rebate.

12) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the BPPR based on the share of energy withdrawn for the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* for the MPMA Rebate and by customers of retailers who have assigned all or a portion of their entitlement to an MPMA Rebate to that retailer. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the BPPR for that quarter in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

13) For the quarterly periods from May 1, 2003 to January 31, 2005, after making the payments set out in 10), 11), and 12), the IESO is to pay any remaining Rebate to the Ontario Electricity Financial Corporation to offset in whole or in part the cost of providing the prices established under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* to consumers who are eligible to receive the prices established under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998.* Any amounts returned to the IESO by distributors in accordance with their license conditions shall be paid over to the Ontario Electricity Financial Corporation.

For the Payment for the Period (February 1, 2005 to March 31, 2005)

14) For the Payment for the Period from February 1, 2005 to March 31, 2005, OPG is to make an MPMA Rebate payment to the IESO, consistent with OPG's MPMA license conditions, as calculated by the IESO and agreed to by OPG. The IESO and OPG may agree to appropriate true-up and carry forward mechanisms provided that these are consistent with forwarding the Rebate as soon as practicable.

15) For the Payment for the Period from February 1, 2005 to March 31, 2005 the MPMA rebate payments to market participants will be calculated and determined by the IESO as follows:

BPPR = [(WAP – CAP) x 0.5 x TAQEW]

Where:
"Business Protection Plan Rebate" or "BPPR" is the MPMA Rebate paid out to consumers who are not receiving the fixed price under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998*. The BPPR is to rebate half of the amount by which the weighted average commodity price of electricity exceeds 3.8 cents per kilowatt hour.

"Weighted Average Price" or "WAP" is the average Hourly Ontario Electricity Price weighted by load over the Settlement Period as determined by the IESO.
"Total Allocated Quantity of Energy Withdrawn" or "TAQEW" is the total electricity withdrawn from the IESO-controlled grid for use in Ontario during the Settlement Period.

16) The IESO will make the MPMA payment to market participants for the two month period ending March 31, 2005 taking into account all prior MPMA payments made in that Settlement Period.

17) The IESO will pay the pro rata share of the BPPR based on the allocated quantity of energy withdrawn for the applicable period by market participants who are receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act*, *1998* to the Ontario Electricity Financial Corporation.

18) The IESO will pay the pro rata share of the BPPR based on the allocated quantity of energy withdrawn for the applicable period by market participants who are not distributors and are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their MPMA Rebate.

19) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the BPPR based on the share of energy withdrawn for the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board, Act 1998* for the MPMA Rebate and by customers of retailers who have assigned all or a portion of their entitlement to an MPMA Rebate to that retailer. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the BPPR for that quarter in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

20) After making the payments set out in 17), 18), and 19), the IESO is to pay any remaining Rebate to the Ontario Electricity Financial Corporation to offset in whole or in part the cost of providing the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* to consumers who are eligible to receive the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998.* Any amounts returned to the IESO by distributors in accordance with their license conditions shall be paid over to the Ontario Electricity Financial Corporation.

Replacement of the MPMA Rebate With A New Payment for the Period (April 1, 2005 to December 31, 2005)

21) For the Payment for the Period from April 1, 2005 to December 31, 2005, OPG is to make a single payment to the IESO, calculated as follows:

Payment = Sum over all hours [(HOEP - $47) x (ONPA (output) x 0.85)]

Where:
ONPA or OPG's Non-Prescribed Assets are those generation assets operated and controlled by Ontario Power Generation, excluding Lennox Generating Station, that are not prescribed assets under section 78.1 of the *Ontario Energy Board Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

HOEP is the Hourly Ontario Energy Price as determined by the IESO.

ONPA (output) is the generation output from OPG's Non-Prescribed Assets generation assets over each hour of the period adjusted to take account of volumes sold through Transitional Rate Option contracts and forward contracts in effect as of January 1, 2005.

22) For the Payment for the Period from April 1, 2005 to December 31, 2005 the single payment to market participants will be equal to the payment calculated in 21) above.

23) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable period by market participants who are receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act*, *1998* to the

Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004.*

24) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable period by market participants who are not distributors and are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their Payment.

25) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the Payment based on the share of energy withdrawn for the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* for the Payment and by customers of retailers who have assigned all or a portion of their entitlement to a Payment to that retailer. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the Payment for the period in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

26) After making the payments set out in 23), 24), and 25), the IESO is to pay any remaining amount of the Payment to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

27) With respect to its non-prescribed generating facilities, OPG shall maximize their value to the people of Ontario by operating those facilities in response to the price signals of the IESO-administered markets. OPG's conduct in the IESO-administered markets under this direction is subject to review by the Market Surveillance Panel of the Ontario Energy Board.

Replacement of the MPMA Rebate With A New Payment for the Period (January 1, 2006 to April 30, 2006)

28) For the Payment for the Period from January 1, 2006 to April 30, 2006, OPG is to make a single payment to the IESO, calculated as follows:

Payment = Sum over all hours [[(HOEP - $47) x (ONPA (output) x 0.85)] + [(PA (price) - $52) x (PA (amount))]]

Where:
ONPA or OPG's Non-Prescribed Assets are those generation assets operated and controlled by Ontario Power Generation, excluding Lennox Generating Station, that are not prescribed assets under section 78.1 of the *Ontario Energy Board Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

HOEP is the Hourly Ontario Energy Price as determined by the IESO.

ONPA (output) is the generation output from OPG's Non-Prescribed Assets generation assets over each hour of the period adjusted to take account of volumes sold through Transitional Rate Option contracts and forward contracts in effect as of January 1, 2005 and volumes sold through the Pilot Auction administered by the Ontario Power Authority in the first half of 2006 with sales volumes commencing on April 1, 2006.

PA is the Pilot Auction administered by the Ontario Power Authority in the first half of 2006, which includes a limited amount of output from OPG's non-prescribed assets, with sales to commence on April 1, 2006.

PA (amount) is the hourly volume in MWh of OPG non-prescribed assets output sold through the Pilot Auction administered by the Ontario Power Authority in the first half of 2006 with sales commencing on April 1, 2006.

PA (price) is the weighted average auction price in $/ MWh realized in each hour of the Period for the output of the limited amount of OPG non-prescribed assets output volume sold through the Pilot Auction administered by the Ontario Power Authority in the first half of 2006 with sales volumes commencing on April 1, 2006.

29) For the Payment for the Period from January 1, 2006 to April 30, 2006 the single Payment to market participants will be equal to the Payment calculated in 28) above.

30) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable period by market participants who are receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act*, *1998* to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004.*

31) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable period by market participants who are not distributors and are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their Payment.

32) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the Payment based on the share of energy withdrawn for the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* for the Payment and by customers of retailers who have assigned all or a portion of their entitlement to a Payment to that retailer. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the Payment for the period in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

33) After making the payments set out in 30), 31), and 32), the IESO is to pay any remaining amount of the Payment to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

34) With respect to its non-prescribed generating facilities, OPG shall maximize their value to the people of Ontario by operating those facilities in response to the price signals of the IESO-administered markets. OPG's conduct in the IESO-administered markets under this direction is subject to review by the Market Surveillance Panel of the Ontario Energy Board.

OPG Rebate for the Period (May 1, 2006 to April 30, 2009)

35) For the Period from May 1, 2006 to April 30, 2009, OPG is to make quarterly Payments to the IESO, as calculated by the IESO and agreed to by OPG as follows:

Payment = Sum over all hours [(HOEP – ORL) x (ONPAO x 0.85 – PAA) + (PAP – PAORL) x PAA)]

Ontario Power Generation's quarterly payments will be based on a cumulative calculation commencing May 1, 2006 to the end of each quarter less the same cumulative calculation to the end of the previous quarter. This will continue until the final quarter ending April 30, 2009. For greater certainty, where the payment formula results in an amount owing to OPG for any quarter, no such payment will be made to OPG by the IESO and any such amount will be carried forward into subsequent quarters.

Where:

ONPA or OPG's Non-Prescribed Assets are those generation assets operated and controlled by Ontario Power Generation assets in service as of January 1, 2006, excluding Lennox Generating Station and excluding stations whose generation output is subject to a contract with the Ontario Power Authority (OPA) in the form of a hydroelectric energy supply agreement [entered into by the OPA and OPG pursuant to a ministerial direction made under section 25.32 of the *Electricity Act, 1998*], that are not prescribed assets under section 78.1 of the *Ontario Energy Board Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

HOEP is the Hourly Ontario Energy Price as determined by the IESO.

ONPAO is the generation output from OPG's Non-Prescribed Assets, over each hour of the quarter adjusted to take account of volumes sold through forward contracts in effect as of January 1, 2005. For greater certainty, any output from ONPA resulting from fuel conversion by Ontario Power Generation in ONPA, or incremental output from ONPA resulting from refurbishment or expansion, or is subject to a contract with the OPA in the form of a hydroelectric energy supply agreement, [entered into by the OPA and OPG pursuant to a ministerial direction made under section 25.32 of the *Electricity Act, 1998*] is to be excluded from ONPAO.

Incremental Output is defined as:
generation output x (new total installed capacity – installed capacity as of January 1, 2006) / new total installed capacity.
ORL is the Ontario Power Generation Revenue limit.
For the period May 1, 2006 to April 30, 2007 ORL is equal to $46/ MWh.
For the period May 1, 2007 to April 30, 2008 ORL is equal to $47/ MWh.
For the period May 1, 2008 to April 30, 2009 ORL is equal to $48/ MWh.

PA is the Pilot Auction administered by the Ontario Power Authority in the first half of 2006.

PAA is the volume in MWh over each hour in the quarter that is sold by Ontario Power Generation through the PA.

PAORL is the Pilot Auction Ontario Power Generation Revenue limit.
For the period May 1, 2006 to April 30, 2007 PAORL is equal to $51/ MWh.
For the period May 1, 2007 to April 30, 2008 PAORL is equal to $52/ MWh.
For the period May 1, 2008 to April 30, 2009 PAORL is equal to $53/ MWh.

PAP is the weighted average auction price in $/ MWh over each hour of the quarter realized for the PAA by Ontario Power Generation.

36) For the Payment for the Period from May 1, 2006 to April 30, 2009 quarterly payments made by the IESO to market participants will be equal to the quarterly Payment calculated in 35) above. In the event of any quarterly Payment calculated in 35) above being negative, no quarterly payment will be made by the IESO to market participants.

37) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable quarter by market participants who are receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act*, *1998* to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004.*

38) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable quarter by market participants who are not distributors and are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* directly to those market participants.

39) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the Payment based on the share of energy withdrawn for the applicable quarter by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* for the Payment. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the Payment for the quarter in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

40) After making the payments set out in 37), 38), and 39), the IESO is to pay any remaining amount of the Payment to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

41) With respect to its non-prescribed generating facilities, OPG shall maximize their value to the people of Ontario by operating those facilities in response to the price signals of the IESO-administered markets. OPG's conduct in the IESO-administered markets under this direction is subject to review by the Market Surveillance Panel of the Ontario Energy Board.

SCHEDULE 1 LIST OF LICENSED GENERATION FACILITIES

The Licence authorizes the Licensee only in respect to the following:

1. The ownership and operation of Darlington Nuclear Generating Station, located at Bowmanville, Ontario.

2. The ownership and operation of Pickering Nuclear Generating Station A, located at Pickering, Ontario.

3. The ownership and operation of Pickering Nuclear Generating Station B, located at Pickering, Ontario.

4. The ownership and operation of Atikokan, located at Atikokan, Ontario.

5. The ownership and operation of Lennox, located at Greater Napanee, Ontario.

6. The ownership and operation of Abitibi Canyon, located at Smooth Rock Falls, Ontario.

7. The ownership and operation of Aguasabon, located at Thunder Bay, Ontario.

8. The ownership and operation of Alexander, located at Nipigon, Ontario.

9. The ownership and operation of Arnprior, located at Arnprior, Ontario.

10. The ownership and operation of Auburn, located at Peterborough, Ontario.

11. The ownership and operation of Barrett Chute, located at Renfrew, Ontario.

12. The ownership and operation of Big Chute, located at Coldwater, Ontario.

13. The ownership and operation of Big Eddy, located at Bala, Ontario.

14. The ownership and operation of Bingham Chute, located at Powassan, Ontario.

15. The ownership and operation of Calabogie, located at Renfrew, Ontario.

16. The ownership and operation of Cameron Falls, located at Nipigon, Ontario.

17. The ownership and operation of Caribou Falls, located at Kenora, Ontario.

18. The ownership and operation of Chats Falls (Units 2-5), located at Ottawa, Ontario.

19. The ownership and operation of Chenaux, located at Renfrew, Ontario.

20. The ownership and operation of Chute, located at Elk Lake, Ontario.

21. The ownership and operation of Coniston, located at Coniston, Ontario.

22. The ownership and operation of Crystal Falls, located at Sturgeon Falls, Ontario.

23. The ownership and operation of DeCew Falls I, located at St. Catherines, Ontario.

24. The ownership and operation of DeCew Falls II, located at St. Catherines, Ontario.
25. The ownership and operation of Des Joachims, located at Deep River, Ontario.
26. The ownership and operation of Ear Falls, located at Ear Falls, Ontario.
27. The ownership and operation of Elliot Chute, located at Powassan, Ontario.
28. The ownership and operation of Eugenia Falls, located at Meaford, Ontario.
29. The ownership and operation of Frankford, located at Frankford, Ontario.
30. The ownership and operation of Hagues Reach, located at Campbellford, Ontario.
31. The ownership and operation of Hanna Chute, located at Bracebridge, Ontario.
32. The ownership and operation of Healey Falls, located at Campbellford, Ontario.
33. The ownership and operation of High Falls, located at Perth, Ontario.
34. The ownership and operation of Kakabeka Falls, located at Thunder Bay, Ontario.
35. The ownership and operation of Lac Seul, located at Ear Falls, Ontario.
36. The ownership and operation of Lakefield, located at Lakefield, Ontario.
37. The ownership and operation of Lower Notch, located at North Cobalt, Ontario.
38. The ownership and operation of Manitou Falls, located at Ear Falls, Ontario.
39. The ownership and operation of Matabitchuan, located at North Cobalt, Ontario.
40. The ownership and operation of McVittie, located at Sudbury, Ontario.
41. The ownership and operation of Merrickville, located at Smith Falls, Ontario.
42. The ownership and operation of Meyersberg, located at Campbellford, Ontario.
43. The ownership and operation of Mountain Chute, located at Renfrew, Ontario.
44. The ownership and operation of Nipissing, located at Nipissing, Ontario.
45. The ownership and operation of Otter Rapids, located at Kapuskasing, Ontario.
46. The ownership and operation of Otto Holden, located at Mattawa, Ontario.
47. The ownership and operation of Pine Portage, located at Nipigon, Ontario.
48. The ownership and operation of Robert H. Saunders, located at Cornwall, Ontario.
49. The ownership and operation of Ragged Rapids, located at Bala, Ontario.
50. The ownership and operation of Ranney Falls, located at Campbellford, Ontario.

51. The ownership and operation of Seymour, located at Campbellford, Ontario.

52. The ownership and operation of Sidney, located at Trenton, Ontario.

53. The ownership and operation of Sills Island, located at Frankford, Ontario.

54. The ownership and operation of Silver Falls, located at Thunder Bay, Ontario.

55. The ownership and operation of Sir Adam Beck I, located at Queenston, Ontario.

56. The ownership and operation of Sir Adam Beck II, located at Queenston, Ontario.

57. The ownership and operation of Sir Adam Beck PGS, located at Queenston, Ontario.

58. The ownership and operation of South Falls, located at Bracebridge, Ontario.

59. The ownership and operation of Stewartville, located at Arnprior, Ontario.

60. The ownership and operation of Stinson, located at Sudbury, Ontario.

61. The ownership and operation of Trethewey Falls, located at Bracebridge, Ontario.

62. The ownership and operation of Whitedog Falls, located at Kenora, Ontario.

63. The ownership of Bruce Nuclear Generating Station A[1], located at Tiverton, Ontario.

64. The ownership of Bruce Nuclear Generating Station B[2], located at Tiverton, Ontario.

65. The operation of Chats Falls (Units 6-9), located at Ottawa, Ontario.

66. The operation of Harmon (LMELP)[3], located at Kapuskasing, Ontario.

67. The operation of Kipling (LMELP)[4], located at Kapuskasing, Ontario.

68. The operation of Little Long (LMELP)[5], located at Kapuskasing, Ontario.

[1] Operated by Bruce Power Inc. under the authority of its electricity generation licence EG-2018-0272.
[2] Operated by Bruce Power Inc. under the authority of its electricity generation licence EG-2018-0272.
[3] Owned by Lower Mattagami Energy Limited Partnership under the authority of its electricity generation licence EG-2010-0254.
[4] Owned by Lower Mattagami Energy Limited Partnership under the authority of its electricity generation licence EG-2010-0254.
[5] Owned by Lower Mattagami Energy Limited Partnership under the authority of its electricity generation licence EG-2010-0254.

SCHEDULE 2 AUTHORIZED TRADE NAMES

1. None

Canadian Nuclear Safety Commission
Commission canadienne de sûreté nucléaire

Regulatory Document

RD–360

Life Extension of Nuclear Power Plants

February 2008

Canada

CNSC REGULATORY DOCUMENTS

The Canadian Nuclear Safety Commission (CNSC) develops regulatory documents under the authority of paragraphs 9(b) and 21(1)(*e*) of the *Nuclear Safety and Control Act* (NSCA).

Regulatory documents provide clarifications and additional details to the requirements set out in the NSCA and the regulations made under the NSCA, and are an integral part of the regulatory framework for nuclear activities in Canada.

Each regulatory document aims at disseminating objective regulatory information to stakeholders, including licensees, applicants, public interest groups and the public on a particular topic to promote consistency in the interpretation and implementation of regulatory requirements.

A CNSC regulatory document or any part thereof becomes a legal requirement when it is referenced in a licence or any other legally enforceable instrument.

Regulatory Document

RD–360

LIFE EXTENSION OF NUCLEAR POWER PLANTS

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Life Extension of Nuclear Power Plants

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Document availability

The document can be viewed on the CNSC web site at www.nuclearsafety.gc.ca. Copies may be ordered in English or French using the contact information below:

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LIFE EXTENSION OF NUCLEAR POWER PLANTS

1.0 PURPOSE

This regulatory document is one of a suite of regulatory documents that cover the life cycle of Canadian nuclear power plants from siting and design to operation and decommissioning. The purpose of this regulatory document is to inform licensees about the steps and phases to consider when undertaking a project to extend the life of a nuclear power plant (NPP).

2.0 SCOPE

This regulatory document addresses:

1. Key elements to consider when establishing the scope of the life extension project; and
2. Considerations to be taken into account in planning and executing a life extension project.

3.0 RELEVANT LEGISLATION

The following provisions of the *Nuclear Safety and Control Act* (NSCA) and related regulations are relevant to this regulatory document:

1. Section 3 of the NSCA provides for, "the limitation, to a reasonable level and in a manner that is consistent with Canada's international obligations, of the risks to national security, the health and safety of persons and the environment that are associated with the development, production and use of nuclear energy…";
2. Section 9 of the NSCA provides the objects of the Commission, which are, "to regulate the development, production and use of nuclear energy and the production, possession and use of nuclear substances, prescribed equipment and prescribed information…";
3. Subsection 24(4) of the NSCA stipulates that, "No licence may be issued, renewed, amended or replaced unless, in the opinion of the Commission, the applicant
   (*a*) is qualified to carry on the activity that the licence will authorize the licensee to carry on; and
   (b) will, in carrying on that activity, make adequate provision for the protection of the environment, the health and safety of persons and the maintenance of national security and measures required to implement international obligations to which Canada has agreed";
4. Subsection 24(5) of the NSCA provides that, "a licence may contain any term or condition that the Commission considers necessary for the purposes of the Act…";

5. Section 3 of the *General Nuclear Safety and Control Regulations* contains the general licence application requirements;
6. Paragraph 12(1)(*c*) of the *General Nuclear Safety and Control Regulations* says that every licensee shall, “take all reasonable precautions to protect the environment and the health and safety of persons and to maintain security”;
7. Paragraph 12(1)(*f*) of the *General Nuclear Safety and Control Regulations* says that every licensee shall, “take all reasonable precautions to control the release of radioactive nuclear substances or hazardous substances within the site of the licensed activity and into the environment as a result of the licensed activity”;
8. Paragraph 12(1)(*i*) of the *General Nuclear Safety and Control Regulations* stipulates that every licensee shall, “take all necessary measures to facilitate Canada's compliance with any applicable safeguards agreement”;
9. Section 3 of the *Class I Nuclear Facilities Regulations* outlines the general licence application requirements specific to nuclear power plants; and
10. Section 6 of the *Class I Nuclear Facilities Regulations* stipulates the information that is required in an application for a nuclear power plant operating licence.

Regulations associated with the *Canadian Environmental Assessment Act* will also be applicable to a life extension project. Other relevant legislation is listed in the Associated Documents section at the end of this regulatory document.

4.0 INTRODUCTION

Nuclear power plants in Canada are subject to the ongoing regulatory oversight of the Canadian Nuclear Safety Commission (CNSC, the Commission), including periodic licence renewal. However, the NPP licensee may choose, for the purpose of long-term operation, to implement a life extension project. Continued operation of the NPP is largely dependent on the work that will be required for long term safe operation of the plant.

A life extension project may involve the replacement or refurbishment of major components, or substantial modifications to the plant, or both. As such, these projects represent a commitment to long-term, continued operation of the facility. In keeping with the objectives of the NSCA, the Commission is mandated to ensure that facility operation continues to pose no unreasonable risk to health, safety, security, or the environment, and will conform to Canada’s international obligations.

The Commission therefore considers it to be in the public interest that licensees address modern high level safety goals, and meet applicable regulatory requirements for safe and secure long-term operation. To this end, NPP licences are amended to introduce specific licence conditions for the regulatory control of life extension projects. The licensee is expected to adhere to the requirements of the NSCA and the *Canadian Environmental Assessment Act*, and all associated regulations, and to all licence conditions throughout the life extension project and subsequent reactor operation.

Approval for return-to-service is contingent upon demonstration by the licensee that all licence conditions have been met.

In keeping with its regulatory mandate, the Commission expects the licensee to demonstrate that the following objectives are met for any life extension project:

1. The technical scope of the project is adequately determined through a Integrated Implementation Plan that takes into account the results of an environmental assessment (EA), where required, and an Integrated Safety Review (ISR);
2. Programs and processes that take into account the special considerations of the project are established; and
3. The project is appropriately planned and executed.

5.0 PROJECT INITIATION

The licensee formally advises the Commission of the intention to conduct a life extension project, and submits a project description with this notification. The project description indicates the licensee's initial understanding of the project, and includes:

1. Definition of project scope and objectives;
2. Status of current plant design and operation;
3. Project components and structures (such as permanent and temporary structures, infrastructure, construction equipment, etc.);
4. Expected project activities (such as operational phases, timing and scheduling of each phase, etc.);
5. Site information (such as location, environmental features, and land use);
6. Waste issues; and
7. Anticipated milestones.

The project description forms the basis of the EA, and is also used as a point of reference for the project.

Information to assist the licensee in developing the project description is provided in the Canadian Environmental Assessment Agency's publication, *Preparing Project Descriptions under the Canadian Environmental Assessment Act*.

6.0 ESTABLISHING THE INTEGRATED IMPLEMENTATION PLAN

Once the licensee decides to undertake a life extension project, the licensee systematically identifies and addresses all environmental and safety concerns, and integrates them into an *Integrated Implementation Plan*. To do this, the licensee:

1. Participates in the environmental assessment (EA) process (Section 6.1, below);
2. Carries out an Integrated Safety Review (Section 6.2, below); and
3. Applies the results of these assessments to establish the Integrated Implementation Plan (Section 6.3.2, below).

Since the EA and ISR may provide information relevant to each other, these assessments are done in parallel where practicable.

6.1 Environmental Assessment

In accordance with the *Canadian Environmental Assessment Act*, the life extension project may be subject to an environmental assessment. Where an EA is required, a decision that the life extension project will not have significant adverse environmental effects is needed prior to any licensing action being taken under the NSCA.

As the responsible authority for the conduct of the EA process, the Commission is responsible for determining whether an EA is required, and ensuring that the process is carried out appropriately.

6.2 Integrated Safety Review

The *Integrated Safety Review* (ISR) is a comprehensive assessment of plant design, condition, and operation. It is conducted at the time that a licensee is considering life extension of an NPP. Guidance on the ISR is found in the *Periodic Safety Review of Nuclear Power Plants – Safety Guide* (IAEA PSR Guide) published by the International Atomic Energy Agency (IAEA). It is referred to as an ISR due to its application of the *Periodic Safety Review* to the life extension project.

Performed by the licensee, the ISR involves an assessment of the current state of the plant and plant performance to determine the extent to which the plant conforms to modern standards and practices, and to identify any factors that would limit safe long-term operation. Operating experience in Canada and around the world, new knowledge from research and development activities, and advances in technology, are taken into account. This enables determination of reasonable and practical modifications that should be made to systems, structures, and components, and to management arrangements, to enhance the safety of the facility to a level approaching that of modern nuclear power plants, and to allow for long term operation.

The objectives of the ISR are to determine:

1. The extent to which the plant conforms to modern standards and practices;
2. The extent to which the licensing basis will remain valid over the proposed extended operating life;
3. The adequacy of the arrangements that are in place to maintain plant safety for long-term operation; and
4. The improvements to be implemented to resolve safety issues that have been identified.

The ISR should include:

1. Conformity reviews that confirm that the NPP meets and will continue to meet the current plant-specific licensing and design basis;
2. A review against modern standards and practices to assess the level of safety compared to that of modern NPPs (any shortcomings against these modern standards and practices are identified and their safety significance determined);
3. Any modifications that are necessary to improve the level of safety; and
4. A global assessment of plant safety for long-term operation in view of each of the ISR safety factors.

6.2.1 ISR Basis

Prior to performing the ISR, the licensee prepares an *ISR Basis Document*, which sets out the scope and methodology for the conduct of the ISR. The *ISR Basis Document* includes the following information:

1. **The proposed extended life of the facility**

   The *ISR Basis Document* clearly defines the full period of proposed extended operation. This information is also included in the project description if an EA is required.

2. **The scope of the ISR**

   The safety factors to be addressed in the ISR are listed in the IAEA's safety guide, *Periodic Safety Review of Nuclear Power Plants*. In addition, the scope of the ISR should at least address CNSC safety areas and programs (refer to Appendix A).

   The ISR should address site-specific facilities, systems, structures, and components, and any applicable site-wide issues, such as dependencies on common services. The physical status of' each unit should be considered separately for an ISR of multiple units of the same design. The adequacy of management arrangements should also be addressed.

In addition, the ISR scope should consider, as appropriate for each safety factor, all expected modes of operation (i.e., normal operation, maintenance, refuelling, shutdown, and start-up activities), to determine whether there is any potential for increased or unacceptable levels of risk.

All generic action items and station-specific actions items should be addressed in the review, with each being resolved to the extent practicable.

3. **Statement of modern standards and practices**

   The set of modern standards and practices that will be used in the review of each ISR safety factor should be provided, including the criteria for the selection of applicable standards and specifications.

   Primary consideration should be given to CNSC regulatory documents that would apply to a new facility, as well as to standards currently referenced in licences. The licensee should also consider IAEA or other appropriate modern international standards and practices.

   For each document listed, the licensee should indicate whether a high-level review, a clause-by-clause review will be performed, or whether an alternative approach will be taken. The rationale for the selected approach should be outlined.

4. **Statement of the plant licensing basis at the time of initiating the ISR**

   The licensing basis is used in conformity reviews, and also serves as the baseline in the review against the modern standards and practices.

   The licensing basis includes the CNSC regulatory framework, the documents referenced in the station-specific licence, the documents submitted by the licensee in support of the licence application, and the documents referenced therein.

5. **Process for identifying and addressing gaps**

   The licensee describes its processes for identifying and addressing gaps between current and desired plant state and performance, documenting the significance of any gaps, and prioritizing corrective actions and safety improvements.

   Non-compliance with the current licensing and design basis should be addressed immediately by the licensee. Non-compliance with modern standards and practices should be resolved to the extent practicable. An appropriate justification should be provided for any unresolved shortcomings.

The Commission reviews the *ISR Basis Document* for acceptance.

6.2.2 ISR Safety Factor Reports

The licensee considers all pertinent safety factors and prepares *ISR Safety Factor Reports* for submission to the Commission. The licensee proposes the manner in which the scope of the ISR will be addressed, and either submits reports addressing each ISR safety factor separately, or groups documentation accordingly.

The *ISR Safety Factor Reports* contain the review results, including proposed corrective actions and safety improvements, for the specific topics. The results of the conformity reviews and the comparison against modern standards and practices are also included.

6.2.3 Confirmation of the Adequacy of ISR Safety Factor Reports

The Commission reviews the *ISR Safety Factor Reports* for acceptance. The final results are incorporated in the development of the licensee's *Integrated Implementation Plan*.

6.3 Global Assessment and Integrated Implementation Plan

The licensee incorporates the results of the EA and the *ISR Safety Factor Reports* in a *Global Assessment Report*, which includes an *Integrated Implementation Plan*.

6.3.1 Global Assessment

The *Global Assessment Report* presents significant ISR results, including plant strengths, the *Integrated Implementation Plan* for corrective actions and safety improvements, and an overall risk judgment on the acceptability of continued plant operation. Interactions between safety factors, individual shortcomings, corrective actions, and safety improvements, including compensatory measures, should be considered in assessing the overall plant safety and the acceptability of continued operation. The global assessment should also show the extent to which the safety requirements of the defence-in-depth concept are fulfilled.

6.3.2 Integrated Implementation Plan

When developing the *Integrated Implementation Plan*, the licensee:

1. Identifies a list of shortcomings for each of the safety factors identified in the ISR;
2. Identifies a list of strengths with respect to fulfilling the safety requirements of the defence-in-depth concept;
3. Evaluates the safety significance and ranking of each of the shortcomings and prioritizes corrective measures. Significant safety issues should be addressed immediately. Justification for proposed exemptions from the modern standards and practices should be provided, taking the safety significance, physical practicality, and other information into account, as appropriate;
4. Develops corrective actions and safety improvements for each of the shortcomings, as far as practicable; and
5. In view of each of the ISR safety factors, evaluates the acceptability of plant operation over the next review period in an integrated assessment.

The *Integrated Implementation Plan* indicates the schedule for implementing the safety improvements, which should be completed within a reasonable time frame. The licensee provides justification for deferral of the work if the safety improvements cannot be completed during the nearest outage.

The licensee updates all station documentation such as the safety analysis report, operating and maintenance procedures, and training materials to reflect the outcomes of the ISR.

Licensees may elect to submit cost-benefit information in support of the *Integrated Implementation Plan*.

6.4 Confirmation of the Adequacy of the Global Assessment Report

The Commission reviews the licensee's *Global Assessment Report* for acceptability by assessing:

1. The completeness of the assessment;
2. The significance and ranking of identified safety issues for all assessed safety factors;
3. The adequacy of proposed corrective actions and safety improvements, or justification of proposed exemptions;
4. The adequacy of proposed implementation schedule;
5. The adequacy of the proposed measures for assuring the quality of the life extension activities; and
6. Conformance with the EA results.

The results of the Commission reviews are taken into account in the revision of the *Global Assessment Report*, including the *Integrated Implementation Plan.*

The Commission either accepts the *Global Assessment Report,* or requires changes. Upon acceptance of the *Global Assessment Report*, the licence is amended to include licence conditions to be met in the return-to-service phase of the project.

6.4.1 Integrated Implementation Plan Changes

The licensee should have a well defined process for the control of any changes to the *Integrated Implementation Plan*.

Formal approval is required for:

1. Changes in the plan associated with work that is needed to fulfil the requirements identified by the screening EA; and
2. Changes in the plan for items subject to conditions of the operating licence.

7.0 PROJECT EXECUTION

7.1 Project Execution Planning

The licensee prepares a *Project Execution Plan* that identifies what needs to be done to achieve the desired outcomes for the project. Areas that may require special attention when planning the project execution typically include:

1. Historical design issues;
2. Component obsolescence;
3. Resource requirements;
4. Use of contractors;
5. Unique or unusual plant configurations; and
6. Return to service plans.

7.2 Programs and Processes

To enable project implementation, the licensee needs acceptable programs and processes to control and execute the life extension project. These programs and processes may include consideration of such areas as:

1. Change control;
2. Commissioning;
3. Configuration management;
4. Construction;
5. Emergency preparedness;
6. Engineering design;
7. Environmental protection;
8. Fire protection;
9. Human factors;
10. Nuclear criticality safety program;
11. Occupational health and safety;
12. Outage management;
13. Training and personnel qualification;
14. Procurement;
15. Quality management;
16. Radiation protection;
17. Safeguards;
18. Safety management;
19. Security;
20. Stakeholder communication;
21. Waste management; and
22. Work control.

The licensee should refer to Commission requirements and appropriate legislation and standards when addressing these considerations, both for guidance in their development, and to determine how program outcomes will be measured.

The adequacy of programs and processes for the control of the life extension project will be assessed by the Commission.

7.3 Project Monitoring

The licensee is expected to monitor the project for progress, safety, and quality at all phases of execution. Items to be monitored may include:

1. Complete redesigns or design modifications;
2. Engineering field changes;
3. Installation rework;
4. Procedural non-compliances;
5. Plant configuration;
6. Missed completion dates;
7. Worker safety events involving injuries, near misses, unsafe practices, unplanned dose uptakes; and
8. Environmental performance.

Project monitoring includes verifying that the work has been done correctly, and may reveal the need for:

1. Creation of new programs and procedures;
2. Revision of existing programs and procedures;
3. Resource changes;
4. Revision of existing training programs or material; or
5. New training programs or material.

The licensee should assess all identified shortcomings to determine their causes and the impact of the shortcomings or their causes on other aspects of the project.

8.0 RETURN TO SERVICE

The licensee needs to establish a *Return to Service Plan* for the life extension project. Return to service involves returning the reactor, the nuclear systems, and the non-nuclear systems, back to commercial operation. Return to service includes demonstration by the licensee that all relevant licence conditions have been met and that the associated work has been done to the satisfaction of the Commission. The licensee is expected to submit design completion and construction completion assurance reports, as well as completion assurance reports for each phase of commissioning.

8.1 Commissioning Phases

Return to service is dependent on the licensee's ability to demonstrate that new and existing plant systems, structures, and components conform to the defined physical, functional, performance, safety, and control requirements, and that management arrangements have been appropriately updated.

This is accomplished through four commissioning phases:

1. **Phase A:** Focuses on ensuring that those systems required to ensure safety with fuel loaded into the reactor have been adequately commissioned. This phase must be successfully completed prior to loading fuel in the reactor;
2. **Phase B:** Focuses on ensuring the fuel is loaded into the reactor safely, and confirming that the reactor is in a suitable condition to be started up and that all prerequisites for permitting the reactor to go critical have been met. This phase must be successfully completed prior to removal of the guaranteed shutdown state (GSS);
3. **Phase C:** Focuses on confirming reactor behaviour at the stage of initial criticality and subsequent low power tests, and includes activities that cannot be done during the GSS; and
4. **Phase D:** Focuses on demonstrating reactor and systems behaviour at higher power levels, including activities that could not be carried out at the power levels in Phase C.

System baseline data from past commissioning activities should be referenced if available, or new baseline data is established. This may include inaugural and baseline inspections of existing and newly installed systems, structures, and components. In addition, the licensee is expected to define the acceptance criteria for the commissioning tests.

8.2 Milestones

Return to service is achieved through the accomplishment of numerous milestones. Milestones that might be reflected in the return to service stage of a life extension project include:

1. Loading fuel;
2. Removing the guaranteed shutdown state;
3. Heat transport operation;
4. Turbine operation;
5. Turbine synchronization to the grid;
6. Full reactor power; and
7. Specific commissioning tests.

8.3 Hold Points

The process of returning to service includes progressing to regulatory hold points. These hold points are typically aligned with commissioning phases, and may include the milestones listed above. Licence conditions are established for the administration of the hold points, which are then incorporated by the licensee in the *Return to Service Plan*.

Commission approval to remove a given hold point is contingent on licensee submission of a *Completion Assurance Document*. This document presents evidence that all project commitments scheduled for completion prior to removal of the respective hold point have been met. The *Completion Assurance Document* must be accepted by the Commission before authorization to remove the hold point can be issued.

8.4 Return to Normal Operation

Once all Commission approvals have been granted and hold points have been removed, the licensee proceeds to normal operation.

9.0 FOLLOW UP

The licensee will be expected to monitor the adequacy of plant performance and new or updated programs after return to service.

GLOSSARY

Design basis

The range of conditions and events taken into account in the design of the facility, according to established criteria, such that the facility can withstand them without exceeding authorized limits for the planned operation of safety systems.

Design life

The period specified for the safe operation of the facility, systems, structures, and components.

Environmental assessment

An assessment of the environmental effects of the project conducted in accordance with the CEAA and its regulations.

Generic action item

Unresolved safety-related issues that have been singled out by the Commission as requiring corrective actions to be taken by the licensees within a reasonable time frame.

Guaranteed shutdown state (GSS)

A set of conditions that provide sufficient guarantee that the reactor will remain in the shutdown state despite any credible failure.

Hold points

Specific milestones that are built into the commissioning plan to separate critical phases during commissioning, and to allow for regulatory review before transition between phases. Hold points further enable verification of the resolution of issues so that proceeding to the next stage will not pose unreasonable risk to health, safety, security, or the environment.

Integrated safety review (ISR)

A comprehensive assessment of plant design and operation performed in accordance with the IAEA's *Periodic Safety Review of Nuclear Power Plants – Safety Guide*.

Licensing basis

Includes the design basis, and is the set of information that demonstrates that:

1. The facility meets all applicable regulatory and safety requirements, and

2. The applicant and licensee are qualified and have made adequate provisions for safe facility operation.

Life extension

Extending the safe operating life of a nuclear power plant beyond its design life. It involves the replacement or refurbishment of major components, or substantial modifications to the plant, or both.

Modern standards
The set of high-level objectives and requirements for the siting, design, construction, commissioning, operation and decommissioning of a nuclear power plant if it were to be built at the time of the initiation of the life extension project.

Nuclear power plant
Any fission reactor installation constructed to generate electricity on a commercial scale. A nuclear power plant is a Class IA nuclear facility, as defined in the *Class I Nuclear Facilities Regulations*.

Practices

The information contained in modern industrial standards, codes, and practices directly associated with the modern standards. Guidelines should take into account operating experience and findings from technical developments (e.g., new knowledge on the cumulative effects of ageing, results of reactor physics research and development, human factors engineering, human reliability, software engineering).

Prescribed
Means prescribed by federal regulations.

Refurbishment
An activity or a set of activities aimed at restoring the condition of one or several systems to a state that is comparable to the condition of a new system.

ASSOCIATED DOCUMENTS

1. *Nuclear Safety and Control Act*, S.C. 1997, c. 9;
2. *Packaging and Transport of Nuclear Substances Regulations*, SOR/2000-208, May 2000;
3. *Radiation Protection Regulations*, SOR/2000-203, May 2000;
4. *Nuclear Security Regulations*, SOR/2000-209, May 2000;
5. *Nuclear Non-proliferation Import and Export Control Regulations*, SOR/2000-210, May 2000;
6. *Nuclear Substances and Radiation Devices Regulations*, SOR/2000-207, May 2000;
7. *Canadian Nuclear Safety Commission Rules of Procedure*, SOR/2000-211, May 2000;
8. CNSC Regulatory Standard S-99, *Reporting Requirements for Operating Nuclear Power Plants*, March 2003;
9. CNSC Regulatory Policy P-242, *Considering Cost-benefit Information*, October 2000;
10. *Canadian Nuclear Safety Commission - Guidelines for Environmental Assessment pursuant to the requirements of the Canadian Environmental Assessment Act*, Revision 2, December 2004;
11. *Nuclear Liability Act*, R.S.C., 1985, c. N-28;
12. *Canadian Environmental Assessment Act*, S.C. 1992, c. 37;
13. CEAA *Exclusion List Regulations*, SOR/94-639;
14. CEAA *Inclusion List Regulations*, SOR/94-637
15. CEAA *Comprehensive Study List Regulations*, SOR/94-638;
16. *Procedures for an Assessment by a Review Panel*, guidelines issued pursuant to the CEAA, November 1997;
17. *Preparing Project Descriptions under the Canadian Environmental Assessment Act*, Canadian Environmental Assessment Agency, August 2000;
18. *CEAA Law List Regulations*, SOR/94-636, October 1994;
19. *Canadian Environmental Protection Act*, S.C. 1999, c. 33;
20. *Nuclear Fuel Waste Act*, S.C. 2002, c. 23;

21. *Fisheries Act*, R.S.C., 1985, c. F-14;

22. *Species at Risk Act*, S.C. 2002, c. 29;

23. *Migratory Birds Convention Act*, S.C. 1994, c. 22;

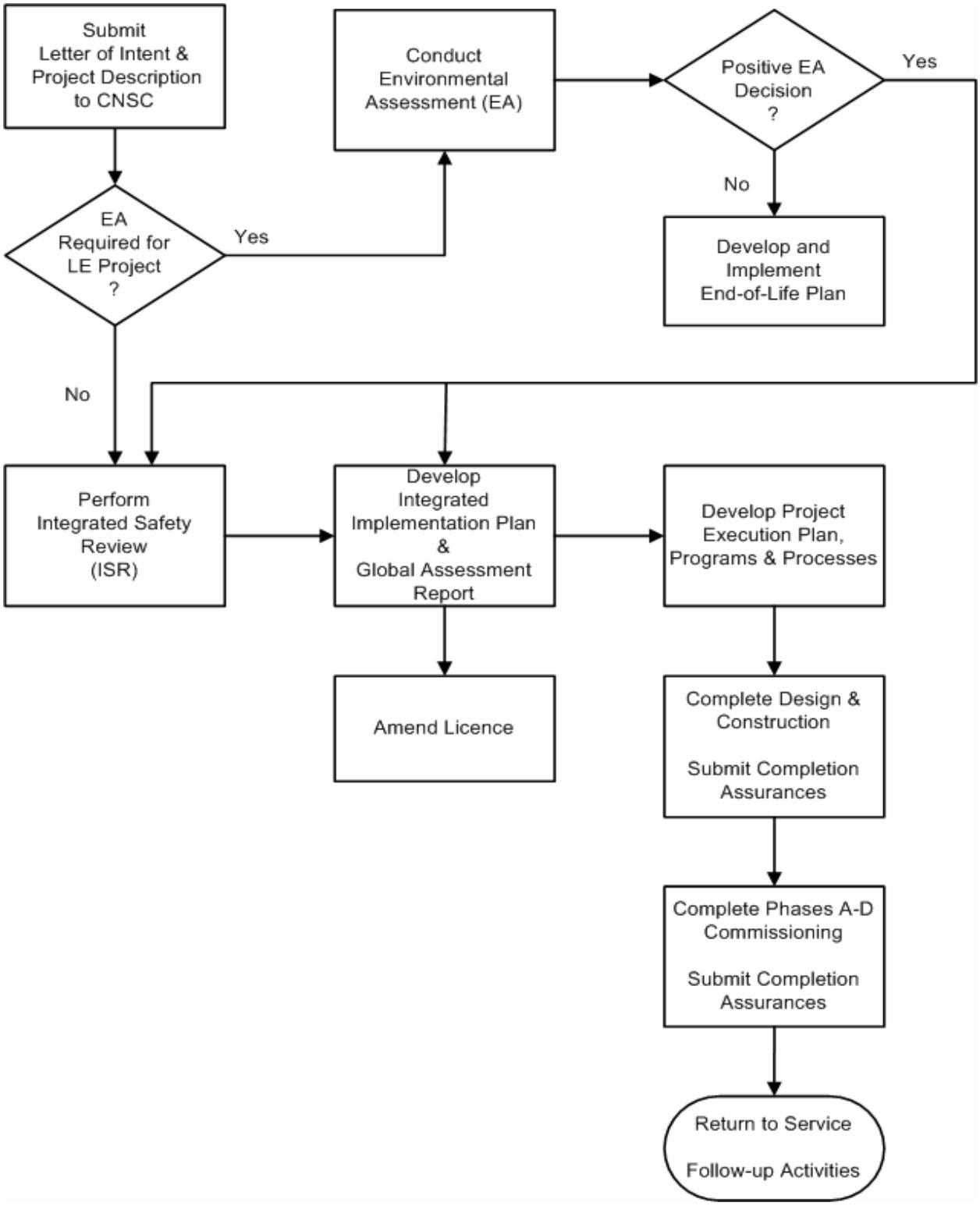
24. *Canada Water Act*, R.S.C., 1985, c. C-11; and

25. *Periodic Safety Review of Nuclear Power Plants—Safety Guide*, Safety Standards Series No. NS-G-2.10, IAEA, Vienna, 2003.

APPENDIX A
CNSC SAFETY AREAS AND PROGRAMS

CNSC Safety Areas	CNSC Programs
1. Operating Performance	1. Organization and Plant Management 2. Operations 3. Occupational Health and Safety (non-radiological)
2. Performance Assurance	1. Quality Management 2. Human Factors 3. Training
3. Design and Analysis	1. Safety Analysis 2. Safety Issues 3. Design
4. Equipment Fitness for Service	1. Maintenance 2. Structural Integrity 3. Reliability 4 Equipment Qualification
5. Emergency Preparedness	1. Emergency Preparedness
6. Environmental Performance	1. Environmental Protection Systems 2. Effluent and Environmental Monitoring
7. Radiation Protection	1. Personnel Exposure 2. Plant Waste Management
8. Site Security	1. Site Security
9. Safeguards	1. Safeguards

APPENDIX B
LIFE EXTENSION PROCESS DIAGRAM



PROCEDURAL ORDERS / CORRESPONDENCE / NOTICES

To be filed behind this tab when procedural orders, correspondence, and notices are filed.

LIST OF WITNESSES

To be filed behind this tab when list of witnesses is filed.

CURRICULA VITAE OF WITNESSES

To be filed behind this tab when curricula vitae of witnesses are filed.

DRAFT ISSUES LIST[1]

1.0 GENERAL

Primary

1.1. Is the overall increase in hydroelectric payment amounts including rate riders reasonable given the overall bill impact on customers?

1.2. Is the overall increase in nuclear payment amounts including rate riders reasonable given the overall bill impact on customers?

Secondary

1.3. Has OPG responded appropriately to all relevant OEB directions from previous proceedings?

1.4. Are OPG's economic and business planning assumptions that impact the prescribed facilities appropriate?

2.0 RATE BASE

Primary

2.1. Are the amounts proposed for the prescribed hydroelectric facilities rate base appropriate?

2.2. Are the amounts proposed for the nuclear facilities rate base appropriate?

2.3. Are the amounts proposed for the Darlington New Nuclear Program ("DNNP") facilities rate base appropriate?

3.0 CAPITAL STRUCTURE AND COST OF CAPITAL

Primary

3.1. Are OPG's proposed capital structure and rate of return on equity appropriate?

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[1] As required by the *Filing Requirements for Ontario Power Generation Inc.*, (September 17, 2024), OPG has proposed preliminary categorization of these issues into "primary" and "secondary" issues. In doing do, OPG has been guided by the OEB's ruling establishing the requirement to divide issues into these categories in EB-2010-0008. In its Decision and Order in that proceeding, the OEB ruled that, for future OPG payment amount applications, "*[I]ssues must be prioritized to ensure that the most significant issues, in terms of dollars and/or in terms of principle, are adequately investigated to ensure an appropriate outcome. The Board and the process are best served by the thorough investigation of the highest priority issues*" (pp. 6-7).

3.2. Are DNNP LP's proposed capital structure and rate of return on equity appropriate?

Secondary

3.3. Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?

3.4. Are DNNP LP's proposed costs for the long-term and short-term debt components of its capital structure appropriate?

4.0 CAPITAL PROJECTS

Hydroelectric

Primary

4.1. Do the costs associated with the hydroelectric projects that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery meet the requirements of that section?

4.2. Are the proposed hydroelectric capital expenditures and/or financial commitments reasonable?

4.3. Are the proposed IR term in-service additions for hydroelectric projects appropriate?

Nuclear

Primary

4.4. Do the costs associated with the nuclear projects that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery meet the requirements of that section?

4.5. Are the proposed nuclear capital expenditures and/or financial commitments (excluding those for the Pickering Refurbishment Program ("PRP") and the DNNP) reasonable?

4.6. Are the proposed IR term in-service additions for nuclear projects (excluding those for the PRP and DNNP) appropriate?

PRP

Primary

4.7. Are the proposed nuclear capital expenditures and/or financial commitments for the PRP reasonable?

4.8. Are the proposed IR term in-service additions for the PRP appropriate?

DNNP

Primary

4.9. Are the proposed nuclear capital expenditures and/or financial commitments for the DNNP reasonable?

4.10. Are the proposed IR term in-service additions for the DNNP appropriate?

5.0 PRODUCTION FORECASTS

Primary

5.1. Is the proposed hydroelectric production forecast appropriate?

5.2. Is the proposed nuclear production forecast appropriate?

5.3. Is the proposed DNNP facilities production forecast appropriate?

6.0 MARKET RENEWAL IMPACTS

Primary

6.1. Is the proposed Hydroelectric Surplus Baseload Generation Variance Account spill calculation methodology appropriate?

6.2. Is the proposed Hydroelectric Incentive Mechanism ("HIM") methodology and HIM adjustment for spill appropriate?

6.3. Is the proposed treatment of make whole payments appropriate?

7.0 OPERATING COSTS

Primary

7.1 Is the IR term Operations, Maintenance and Administration ("OM&A") budget for the hydroelectric facilities appropriate?

7.2 Is the IR term OM&A budget for the nuclear facilities appropriate?

7.3 Is the IR term OM&A budget for the DNNP appropriate?

Secondary

7.4 Is the hydroelectric benchmarking methodology reasonable? Are the benchmarking results and targets flowing from OPG's hydroelectric benchmarking reasonable?

7.5 Is the nuclear benchmarking methodology reasonable? Are the benchmarking results and targets flowing from OPG's nuclear benchmarking reasonable?

Corporate Costs

Primary

7.6 Are the IR term human resource related costs (including wages, salaries, payments under contractual work arrangements, benefits, incentive payments, overtime, FTEs and pension costs) appropriate?

7.7 Are the corporate costs allocated to the hydroelectric business appropriate?

7.8 Are the corporate costs allocated to the nuclear business appropriate?

7.9 Are the corporate costs allocated to the DNNP appropriate?

7.10 Are the centrally held costs allocated to the hydroelectric business appropriate?

7.11 Are the centrally held costs allocated to the nuclear business appropriate?

7.12 Are the centrally held costs allocated to the DNNP appropriate?

Depreciation

Secondary

7.13 Is the proposed IR term hydroelectric depreciation expense appropriate?

7.14 Is the proposed IR term nuclear depreciation expense appropriate?

7.15 Is the proposed IR term DNNP depreciation expense appropriate?

Income and Property Taxes

Secondary

7.16 Are the amounts proposed to be included in the IR term hydroelectric revenue requirement for income and property taxes appropriate?

7.17 Are the amounts proposed to be included in the IR term nuclear revenue requirement for income and property taxes appropriate?

7.18 Are the amounts proposed to be included in the IR term DNNP revenue requirement for income and property taxes appropriate?

Other Costs

Secondary

7.19 Are the asset service fee amounts charged to the hydroelectric business appropriate?

7.20 Are the asset service fee amounts charged to the nuclear business appropriate?

7.21 Are the asset service fee amounts charged to the DNNP appropriate?

8.0 OTHER REVENUES

Non-Energy Revenues

Secondary

8.1 Are the forecasts of prescribed hydroelectric facilities' non-energy revenues appropriate?

8.2 Are the forecasts of nuclear non-energy revenues appropriate?

Bruce Generating Station

Secondary

8.3 Are the IR term costs related to the Bruce Generating Station, and costs and revenues related to the Bruce lease appropriate?

9.0 NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

9.1 Is the revenue requirement impact of the nuclear liabilities appropriately determined?

10.0 DEFERRAL AND VARIANCE ACCOUNTS

Primary

10.1 Are the deferral and variance accounts that OPG proposes to establish appropriate?

Secondary

10.2 Is the nature or type of costs recorded and the methodologies used to record costs in the deferral and variance accounts appropriate?

10.3 Are the balances for recovery and the proposed disposition amounts in each of the deferral and variance accounts appropriate?

10.4 Is the proposed continuation of deferral and variance accounts appropriate?

11.0 REPORTING AND RECORD KEEPING REQUIREMENTS

Secondary

11.1 Are the proposed reporting and record keeping requirements, including performance scorecards proposed by OPG, appropriate?

12.0 METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

Primary

12.1 Is OPG's approach to incentive rate-setting for establishing the hydroelectric payment amounts appropriate?

12.2 Is OPG's approach to incentive rate-setting for establishing the nuclear payment amounts appropriate?

12.3 Do the Concurrent Cost Recovery amounts proposed meet the requirements set out in s. 6(2)12.1i and 14(2)5i of O. Reg. 53/05?

12.4 Is OPG's proposal for intra-period payment amount shaping appropriate?

13.0 IMPLEMENTATION

Primary

13.1 Are the effective dates for new payment amounts and riders appropriate?

SUMMARY OF OEB DIRECTIVES AND UNDERTAKINGS FROM PREVIOUS PROCEEDINGS

This schedule sets out OEB directives to OPG from previous proceedings with reference to where the corresponding evidence may be found in this proceeding. In this case, applicable directives arise from the OEB's decisions on OPG's application for Recovery of Deferral and Variance Account Balances effective December 31, 2022 (EB-2023-0336) and the prior application for payment amounts (EB-2020-0290). The applicable directives from these proceedings are set out in Charts 1 and 2, respectively.

Additionally, Chart 3 provides a continuing OEB directive related to accounting changes impacting the calculation of OPG's nuclear liabilities, and changes to the end-of-life-dates of prescribed nuclear facilities for depreciation and amortization purposes, last confirmed in EB-2016-0152.

Chart 1
Directives from the Decision and Order
on OPG's Application Relating to Impacts from the Market Renewal Program ("MRP")
on OPG's Prescribed Generating Facilities, and the Disposition of Balances in its
Deferral and Variance Accounts as of December 31, 2022 (EB-2023-0336)

Decision Chapter/ Section	Pg. No.	OEB Decision / Directive	Reference Exhibit In OPG Evidence
3	8	OPG agreed to provide quantitative results or outcomes for the prescribed facilities following the effective date of the MRP where available; otherwise, OPG will provide qualitative evidence on its actual experience in the new market for the prescribed facilities.	Ex. E1-2-1, Sections 4.3, 4.5, 5.3.1, 6.1.1 Ex. G1-1-1, Section 3.4
3	8	OPG agreed to provide evidence demonstrating where compensation arising from the liquidated damages for the Manitou Falls Generating Station – Auto Sluice System Replacement project was applied to OPG's regulated hydroelectric work.	On April 29, 2025, OPG entered into a global settlement with Andritz Canada Inc. for issues encountered on three projects, including the Manitou Falls GS Auto Sluice Gates liquidated damages referenced in EB-2023-0336. As a result, OPG is receiving a credit of $1.4M applied to Project #82543 Otter Rapids GS G2 Capital Upgrade and Project #82542 Otter Rapids GS G1 Capital Upgrade.[1]
3	8	Identify options to reduce Surplus Baseload Generation Variance Account amounts in light of the MRP and fund a stakeholder process to obtain input on options to be considered in the study. OPG shall file its report as part of its next rebasing application for the prescribed facilities.	Ex. E1-2-1, Attachment 1

[1] Ex. D1-1-2, Section 3.2.1.

Chart 2
Directives from the Decision and Order on OPG's Application
for payment amounts for the period from January 1, 2022-December 31, 2026
(EB-2020-0290)

Decision Chapter/ Section	Pg. No.	Issue	OEB Decision / Directive	Reference Exhibit in OPG Evidence
5	**D2O Project-Related Issues**			
5.1	47	Allocation of D2O Project Costs (to Decommissioning)	OPG should be prepared to explain its proposed heavy water management plan and provide the costs of heavy water storage associated with decommissioned units as embedded in its Ontario Nuclear Funds Agreement (ONFA) estimates at that time, compared to other available options	Ex. C2-1-1, Section 6.0
Schedule A	**Settlement Proposal**			
	OPG agrees to the reporting and record keeping requirements as set out below:			
Appendix A	2	General/ Custom IR Framework	Customer Engagement Study (continue)	Ex. I1-3-2, Section 4.3, Attachment 1 Ex. A2-2-1, Section 2
		General/ Custom IR Framework	Total Factor Productivity Study and Total Cost Benchmarking for Hydroelectric (if proposing an Incentive Ratemaking Mechanism (IRM)/Custom Incentive Ratemaking (CIR))	Ex. A1-3-2, Attachment 2, Attachment 3
		General/ Custom IR Framework	Total Factor Productivity Study and/or Total Cost Benchmarking for Nuclear (if proposing an IRM / CIR – or explanation as to why it cannot be done for the next major payment amount application)	Ex. A1-3-2, Section 3
		Benchmarking	Nuclear Staffing Benchmarking (continue)	Ex. F2-1-1, Section 3.2.1, Attachment 5
		Benchmarking	Nuclear Benchmarking Approach Review (continue)	Ex. F2-1-1, Section 3.2.1, Attachment 3
		Benchmarking	Corporate Cost Benchmarking (continue)	Ex. F3-1-1, Section 5, Attachment 2

Decision Chapter/ Section	Pg. No.	Issue	OEB Decision / Directive	Reference Exhibit in OPG Evidence
		Compensation & Staffing	Compensation Benchmarking Study on the current two-segment benchmarking approach only (continue	Ex. F4-3-1, Section 8, Attachment 3
		Compensation & Staffing	Pension/OPEBs - most recent actuarial funding valuation, Report on Estimated Accounting Cost for Post-Employment Benefit Plans, Report on the Accounting Cost for Post-Employment Benefit Plans (continue)	Ex. F4-3-2, Attachment 4
		Other Matters	Cost Allocation Study (continue)	Ex. F3-1-4, Attachment 1
		Other Matters	Depreciation Study (continue)	Ex. F4-1-1, Section 3.3, Attachment 1, Attachment 7
		Other Matters	Summary of all internal audit reports (same format as Ex. L-A1-02-SEC-011, Attachment 2) completed subsequent to any that are listed in Ex. L-A1-02-SEC-011, Attachment 1 (new)	Ex. A1-4-1, Attachment 4

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Chart 3
Directives from the Payment Amounts Order on OPG's Application for payment amounts for the period from January 1, 2017-December 31, 2021 (EB-2016-0152)

Page No.	OEB Decision / Directive	Reference Exhibit in OPG Evidence
13	OPG shall file an accounting order application with the OEB and provide notice to intervenors of record in EB-2016-0152 if: i. OPG proposes an accounting change impacting the calculation of its nuclear liabilities, other than as a result of an ONFA Reference Plan update, which results in a material revenue requirement impact for the prescribed facilities; or ii. OPG proposes to change the end-of-life dates of its prescribed nuclear facilities for depreciation and amortization purposes that results in a material non-asset retirement cost revenue requirement impact. An accounting order application shall only be required if the revenue requirement impact is neither reflected in current or proposed payment amounts nor recorded in an authorized deferral or variance account and the annualized revenue requirement impact for the prescribed facilities is $10 million or greater.	Ex. A1-3-2, Section 4.3 Ex. C2-1-1, Section 2 n/a

ACRONYMS

AACE	Association for the Advancement of Cost Engineering International
AAR	Alkali Aggregate Reaction
AAS	Available Actuarial Surplus
ABNO	Available But Not Operating
Aecon	Aecon Construction Group Inc.
ACU	Air Conditioning Unit
AGC	Automatic Generation Control
AI	Artificial Intelligence
AIC	Argument-in-Chief
AIIP	Accelerated Investment Incentive Property
AIM	Advanced Inspection and Maintenance
AIR	All Injury Rate
AMOC	Asset Management Oversight Committee
ANO	Authorized Nuclear Operator
AODA	*Accessibility for Ontarians with Disabilities Act*
ARC	Asset Retirement Costs
ARO	Asset Retirement Obligation
AS9	Asset Suite 9
AS	Ancillary Services
ASF	Asset Service Fee
ASU 2018-15	Accounting Standards Update
Atkins/Aecon JV	AtkinsRéalis/Aecon Joint Venture
AWE	Average Weekly Earnings
BCS	Business Case Summary
Bill 124	*Protecting a Sustainable Public Sector for Future Generations Act*
BIS	Boron Injection System
BOF	Building Ontario Fund
BOP	Balance of Plant
Bruce	Bruce Power L.P.
BSSA	Bruce Site Service Agreement
BTTC	Better Through Total Collaboration
BTU	Building Trades Unions
BWR	Boiling Water Reactors
CAC	Community Advisory Councils
CANDU	Canadian Deuterium Uranium
CBoC	Conference Board of Canada
CCB	Change Control Board
CCoE	Construction Centre of Excellence
CCNS	The Centre for Canadian Nuclear Sustainability

CCR	Concurrent Cost Recovery
CCW	Condenser Cooling Water
CDA	Canadian Dam Association
CEC	Clean Energy Credit
CEO	Chief Executive Officer
C-factor	Custom Capital Factor
CFEP	Collaborative Front End Planning
CFVS	Containment Filtered Venting System
CGF	Canada Growth Fund Inc.
CHQ	Corporate Headquarters
CIA	Canadian Institute of Actuaries
CIB	Canada Infrastructure Bank
CDE	Common Data Environment
CEITC	Clean Electricity Investment Tax Credit
CM	Cyclical Maintenance
CMSC	Congestion Management Settlement Credits
CNO	Chief Nuclear Officer
CNSC	Canadian Nuclear Safety Commission
Concentric	Concentric Energy Advisors
CPI	Consumer Price Index
CPI	Cost Performance Index
CRA	Canada Revenue Agency
CRE	Collective Radiation Exposure
CRVA	Capacity Refurbishment Variance Account
CTS	Corporate & Technology Services
Custom IR	Custom Incentive Rate-setting
CWIP	Construction Work in Progress
D2O Storage Project	Heavy Water Storage and Drum Handling Facility
Darlington	Darlington Nuclear Generating Station
DBB	Design-Bid-Build
DBFOM	Design, Build, Finance, Operate and Maintain
DCC	Digital Control Computer
DCWG	Design Centre Working Group
DEC	Darlington Energy Complex
DES	Data Extraction System
DSF	Decommissioning Segregated Fund
DFO	Fisheries and Oceans Canada
DGR	Deep Geologic Repository
DGSCVA	DNNP Generator Capital Structure Variance Account
Digital Strategy	2024-2028 Digital Business Strategy and Roadmap
DNNP	Darlington New Nuclear Program
DOR	Division of Responsibility
DPSC	Diaphragm Plate Steel Composite
DRBS	DBRS Morningstar

DRC	Depreciation Review Committee
DRP	Darlington Refurbishment Program
DRP RFR Project	Darlington Refurbishment Retube and Feeder Replacement Project
DSP	Design Service Providers
DTP	Darlington Water Treatment Plant
DTS	Digital Technology & Services
DWI	Deep Water Intake
DWP	Demineralized Water Plant
EA	Environmental Assessment
EAM	Enterprise Asset Management
EBIT	Earnings Before Interest and Taxes
EBITDA	Earnings Before Interest Taxes Depreciation and Amortization
EC	Engineering Change
EDI	Equity, Diversion & Inclusion
EEI	Edison Electric Institute
EFOR	Equivalent Forced Outage Rate
EFPH	Equivalent Full Power Hours
EHS	Environment and Health & Safety
EIFEL	Excessive Interest and Financing Expenses Limitation
Elenchus	Elenchus Research Associates
EOL	End-of-Life
EPC	Engineering, Procurement and Construction
EPI	Environmental Performance Index
EPMO	Enterprise Project Management Office
EPSCA	Electrical Power Systems Construction Association
ERP	Enterprise Resource Planning
ESM	Earnings Sharing Mechanism
ESMSA	Extended Services Master Services Agreement
ESB	Engineering Service Building
ESRB	Executive Scope Review Board
ESVOR	Engineering Services Vendor of Record
ETE	Extended Temporary Employee
EUCG	Electric Utility Cost Group
EUP	Enriched Uranium Product
EV	Electric Vehicle
EVM	Earned Value Management
F&I	Facilities and Infrastructure
F&IP	Facility and Infrastructure Projects
FA	Foundation Architecture
FCLE	Fuel Channel Life Extension
FC-LCMP	Fuel Channel Life Cycle Management Plan
FH	Fuel Handling
FLR	Forced Loss Rate

FM	Fueling Machine
FO	Forced Outage
FOAK	First-of-a Kind
4GIRM	Fourth Generation Incentive Rate-setting Mechanism
FSCO	Financial Services Commission of Ontario
FSRA	Financial Services Regulatory Authority of Ontario
FTE	Full-Time Equivalents
Functions	OPG functional support groups
GAAP	Generally Accepted Accounting Principles
GAR	Global Assessment Report
GDP-IPI FDD	Canadian Gross Domestic Product Implicit Price Index – Final Domestic Demand
GE	GE Renewable Energy Canada Inc.
GE-Hitachi	GE-Hitachi Nuclear Energy Americas LLC / GEH SMR Technologies Canada Ltd.
GIP	Grass Island Pool
Global Insight	IHS Markit's Global Insight Economics
GLSHFS	Great Lakes Seasonal Hydrologic Forecast System
GMTA	*Global Minimum Tax Act*
GoC	Government of Canada
Goodnight	Goodnight Consulting Inc.
GRB	Gate Review Board
GRC	Gross Revenue Charges
GS	Generating Station
Hackett	Hackett Group
HIM	Hydroelectric Incentive Mechanism
HOEP	Hourly Ontario Energy Price
HONI	Hydro One Networks Inc.
HST	Harmonized Sales Tax
HVAC	Heating, Ventilation and Air Conditioning System
IAA	Impact Assessment Act
ICAP	Installed Capacity
ICS	Isolation Condenser System
IEP	Government of Ontario's 2025 Integrated Energy Plan
IESO	Independent Electricity System Operator
IF	Irradiated Fuel
IFRS	International Financial Reporting Standards
IIP	Integrated Implementation Plan
IJC	International Joint Commission
ILO-SLRB	International Lake Ontario-St. Lawrence River Board
ILW	Intermediate Level Waste
INC	International Niagara Committee
INCW	International Niagara Control Works
INNOVATIVE	Innovative Research Group Inc.

ION	Indigenous Opportunities Network
IPA	Integrated Project Agreement
IPD	Integrated Project Delivery
IR	Incentive Rate-setting
IRI	Inspection and Reactor Innovation
IRM	Incentive Rate-setting Mechanism
ISAR	Industrial Safety Accident Rate
ISLRBC	International St. Lawrence River Board of Control
IT	Information Technology
ITC	Investment Tax Credits
KgU	Kilogram Uranium
L&ILW	Low and Intermediate Level Waste
LCMP	Life Cycle Management Plan
Leech Report	Report on the Sustainability of Electricity Sector Pension Plans
LEI	London Economics International LLC
LEP	Laurentis Energy Partners
LRIA	*Lakes and Rivers Improvement Act*
LTC	Licence to Construct
LTD	Long-term Disability
MBE	Model-Based Engineering
MCR	Maximum Continuous Rating
MD&A	Management's Discussion and Analysis
MECP	Ministry of Environment, Conservation and Parks
MFA	Minor Fixed Assets
MNR	Ministry of Natural Resources
Moody's	Moody's Investors Service
MPA	Master Product Agreement
MPO	Major Projects Office
MRP	Market Renewal Program
MW	Megawatt
MWh	Megawatt hour
Navigant	Navigant Consulting Inc.
NDVA	Nuclear Development Variance Account
NERC	North American Electric Reliability Corporation
NFOC/MWh	Non Fuel Operating Cost per MWh
NHC	Niagara Hydrogen Centre
NHSS	New Horizon System Solutions
NLDA	Nuclear Liability Deferral Account
NOPs	Non-Owner Parties
Nordion	Nordion Canada Inc.
NPI	Nuclear Performance Index
NTP	Notice to Proceed
NWMO	Nuclear Waste Management Organization

NWO	Northwestern Operations
NYPA	New York Power Authority
NYSIO	New York Independent System Operator
O. Reg.	Ontario Regulation
OAGO	Office of the Auditor General of Ontario
OAR	Organizational Authority Register
OEB	Ontario Energy Board
OEM	Original Equipment Manufacturer
OEFC	Ontario Electricity Financial Corporation
OEM	Original Equipment Manufacturer
OFA	Ontario Financing Authority
OHSA	Occupational Health and Safety Act
OIS	Overnight Indexed Swap
O&M	Operations and Maintenance
OM&A	Operations, Maintenance and Administration
ONFA	Ontario Nuclear Funds Agreement
OPEB	Other Post-Employment Benefits
OPEX	Operating Experience
OPG	Ontario Power Generation Inc.
OPG Board	The Board of Directors of Ontario Power Generation Inc.
OR	Operating Reserve
PBA	*Pension Benefits Act* (Ontario)
PBCR	Project Baseline Change Request
PCB	Polychlorinated Biphenyl
PCV	Primary Containment Vessel
PECO	Pickering End of Commercial Operations
PECO Temps	PECO Temporary Employees
PfAD	Provision for Adverse Deviation
PGS	Pump Generating Station
Pickering	Pickering Nuclear Generating Station
Pickering A	Pickering Units 1 and 4
Pickering B	Pickering Units 5-8
PILs	Payments in Lieu of Corporate, Income, and Capital Taxes
PLC	Pickering Learning Centre
PLT	Project Leadership Team
PM	Preventative Maintenance
PMBOK	Project Management Body of Knowledge
PMF	Pickering Maintenance Facility
PMI	Project Management Institute
PMOC	Program Management Oversight Committee
PMS	Program Milestone Schedule or Primary Moisture Separator
PMSR	Primary Moisture Separator Replacement
PMT	Project Management Team
PO	Planned Outages

POG	Powering Ontario's Growth
POVA	Project Over-Variance Approval(s)
PP&E	Property, Plant and Equipment
PRP	Pickering Refurbishment Program
PSR	Periodic Safety Review
PSR2	Pickering Periodic Safety Review
PSR3	Comprehensive Periodic Safety Review
PSRB	Program Scope Review Board
PTP	Plant Thermal Performance
PWU	Power Workers' Union
RB	Reactor Building
RRB	Refurbishment Review Board
RCCB	Refurbishment Change Control Board
RDM	Rapid Delivery Machine
Renewed Market	IESO's Market Renewal Program
RFBR	Retube, Feeder and Boiler Replacement
RFP	Request for Proposals
RFPQ	Request for Prequalification
RFR	Retube and Feeder Replacement
RG	Renewable Generation
RG PCA	Renewable Generation Programmatic Collaboration Agreement
RNBS	Residual Net Basin Supply model
ROE	Return on Equity
ROP	Regional Overpower Protection
RPP	Registered Pension Plan
RPV	Reactor Pressure Vessel
RQE	Release Quality Estimate
RRB	Refurbishment Review Board
RRF	Renewed Regulatory Framework for Electricity Distributors
RRWF	Revenue Requirement Work Form
RSVC	Reactive Support and Voltage Control
RTS	Return to Service
S&P	S&P Global Ratings
SAB	Sir Adam Beck
SARA	*Species at Risk Act*
SBG	Surplus Baseload Generation
SBGVA	Surplus Baseload Generation Variance Account
SCA	Secondary Control Area or System Condition Assessment
SCO	Station Containment Outage
SEC	Securities and Exchange Commission
SG	Steam Generators
Siemens	Siemens Energy
SIO	Safety Improvement Opportunities

SLSMC	St. Lawrence Seaway Management Corporation
SMO	Segregated Mode of Operation
SMR	Small Modular Reactor
Society	Society of United Professionals
Southlea	Southlea Group
SPI	Schedule Performance Index
SR&ED	Scientific Research and Experimental Development
SR&ED ITC	Scientific Research and Experimental Development Investment Tax Credit
SRP	Stakeholder Return Program
STEM	Science, Technology, Engineering and Math
Superior Court	Ontario Superior Court
SVP	Senior Vice President
TBM	Tunnel Boring Machine
TCA	Technology Collaboration Agreement
TDC	Total Direct Compensation
TG or Turbine Generator	Turbines, Generators and Auxiliaries
TGC	Total Generating Cost
TG Consortium	Agreement with Siemens and Aecon
TGC/MWh	Total Generating Cost per MWh
TIME	Tolerate, Invest, Migrate, or Eliminate
TMF	Training & Mock-up Facility
TREE	Total Recordable Environmental Events
TRIF	Total Recovery Injury Frequency
TRF	Tritium Removal Facility
TSW	Trent Severn Waterway
TWh	Terawatt-hours
U1EE	Unit 1 Execution Estimate
U2EE	Unit 2 Execution Estimate
U3EE	Unit 3 Execution Estimate
U4EE	Unit 4 Execution Estimate
U_3O_8	Uranium Concentrates
UCC	Undepreciated Capital Cost
UCF	Unit Capability Factor
UCLF	Unplanned Capability Loss Factor
UEC	Unit Energy Cost
UF_6	Uranium Hexafluoride
UFF	Used Fuel Segregated Fund
UNL	Unfunded Nuclear Liabilities
UO_2	Uranium Dioxide
UPS	Uninterruptible Power Supply
US GAAP	Generally Accepted Accounting Principles of the United States of America
UxC	Uranium Exchange Company
VBO	Vacuum Building Outage

VOR	Vendor of Record
WACC	Weighted Average Cost of Capital
WANO	World Association of Nuclear Operators
WAPA	Weighted Average Payment Amounts
WTW	Willis Towers Watson
WT	Water Transactions
WTP	Water Treatment Plant

1

FINANCIAL SUMMARY

1.0 PURPOSE

This evidence presents OPG's 2020-2024 audited consolidated financial statements and the unaudited interim consolidated financial statements for the three and nine-months ended September 30, 2025. It includes a discussion of OPG's financial reporting framework and the reconciliation between the audited financial statement results and the regulatory financial results presented in this Application. The financial statements of DNNP LP are expected to be prepared and audited annually under the same accounting standards as OPG's consolidated financial statements.[1]

2.0 OPG'S CONSOLIDATED FINANCIAL STATEMENTS

As required by Ontario Regulation 395/11 under *Financial Administration Act* (Ontario) ("O. Reg. 395/11"), OPG's consolidated financial statements are prepared in accordance with generally accepted accounting principles in the United States ("US GAAP"). OPG is also a reporting issuer under the *Securities Act* (Ontario) (the "Securities Act") and the securities laws of the other Canadian provinces, and is subject to continuous disclosure obligations under provincial securities laws. This includes the requirement to file annual and interim (quarterly) financial statements and certifications on internal control over financial reporting with the Ontario Securities Commission ("OSC"), the principal regulator for OPG, and the other provincial securities regulators.

While the requirements of O. Reg. 395/11 take precedence over the *Securities Act* (and other Ontario legislation, such as the *Business Corporations Act*), they do not take precedence over the equivalent continuous disclosure requirements of other provincial securities regulators. This applies where OPG is also a reporting issuer by virtue of its Medium-Term Notes issued pursuant to a short form base shelf prospectus filed in these jurisdictions and subject to the requirements of *National Instrument 44-101 – Short Form Prospectus Distributions*. As such,

[1] An overview of DNNP LP is provided in Ex. A1-4-4.

since January 1, 2012, OPG has sought and received exemptive relief from the OSC and other provincial securities regulators from the requirements of *National Instrument 52-107* ("NI 52-107") that allows OPG to file its financial statements using US GAAP instead of International Financial Reporting Standards ("IFRS") for continuous disclosure purposes, thereby allowing it to meet the requirements of the other provincial securities laws.[2] The term of the most recent exemption expires on January 1, 2027, subject to certain conditions.[3] In October 2025, OPG filed an application with the OSC requesting the extension of the exemption to the earlier of the effective date of a mandatory IFRS standard for rate-regulated entities (expected to be January 1, 2029) and January 1, 2032.[4]

OPG is not currently planning for adoption of IFRS for continuous disclosure purposes. As further discussed in Ex. C1-1-2, OPG is planning to register with the U.S. Securities and Exchange Commission ("SEC") as a Foreign Private Issuer to facilitate access to U.S. debt capital markets. As an SEC registered issuer, OPG would retain the ability to meet its continuous disclosure requirements in Canada by continuing to file its financial statements using US GAAP as permitted under the ongoing exemptions in NI 52-107 available for SEC registered issuers.

OPG publishes quarterly and annual financial reports on its public website. In particular, OPG's Annual Reports for the years 2020-2024, which include audited annual consolidated financial statements and Management's Discussion and Analysis ("MD&A"), as well as OPG's quarterly consolidated financial statements (unaudited) and MD&A for the first three quarters of 2025 and each of the preceding years are available at: https://www.opg.com/reporting/financial-reports/. OPG has included its four most recent financial reports in Attachment 1-4.

[2] In the event OPG were to file financial statements using IFRS to meet the continuous disclosure requirements of the other provincial securities regulators, it would remain subject to O. Reg. 395/11, which legally requires it to prepare consolidated financial statements in accordance with US GAAP in Ontario.
[3] The current exemption would terminate prior to January 1, 2027, if OPG ceases to have activities subject to rate regulation or on the mandatory effective date of an accounting standard within IFRS specific to entities with rate regulated activities as issued by the International Accounting Standards Board.
[4] The IFRS standard for rate regulated entities is expected to be finalized in the second quarter of 2026.

OPG's financial statements include the accounts of OPG and the entities which OPG consolidates. In accordance with US GAAP, OPG's consolidated financial statements recognize regulatory assets and regulatory liabilities, including those for deferral and variance accounts authorized by the OEB and Ontario Regulation 53/05.

OPG's current reportable segments as reflected in the 2025 third-quarter interim consolidated financial statements are as follows:

- Regulated – Nuclear Generation
- Regulated – Nuclear Sustainability Services (previously Regulated – Nuclear Waste Management in EB-2020-0290)
- Regulated – Hydroelectric Generation
- Contracted Hydroelectric and Other Generation
- Atura Power (previously Gas Generation in EB-2020-0290)

The financial results of DNNP LP will be included within the Regulated – Nuclear Generation segment of OPG's consolidated financial statements. Otherwise, the nature of OPG's reportable segments is substantially unchanged from EB-2020-0290.

In addition to those of the prescribed nuclear facilities, the Regulated – Nuclear Generation and Regulated – Nuclear Sustainability Services segments continue to include assets, liabilities, revenues and costs related to the facilities leased to Bruce Power LP. The items related to the facilities leased to Bruce Power LP are included in this segment for external financial reporting purposes by virtue of their inclusion in the setting of payment amounts by the OEB.

The Contracted Hydroelectric and Other Generation business segment, the Atura Power business segment and the Other category continue to report the financial results of OPG's unregulated operations.

3.0 RECONCILIATION OF FINANCIAL STATEMENT RESULTS TO REGULATORY FINANCIAL RESULTS

Exhibits C1-1-1, Tables 8a-12a sets out a reconciliation of the segmented earnings for the Regulated – Nuclear Generation, Regulated – Nuclear Sustainability Services and Regulated – Hydroelectric Generation segments as reported in OPG's audited consolidated financial statements for each of the years 2020-2024 and the corresponding historical regulated earnings before tax for the prescribed facilities. In addition to reflecting deemed cost of capital methodologies, the main reconciling items relate to the exclusion of revenues and costs related to the facilities leased to Bruce Power LP (see Ex. G2-2-1), the exclusion of the accretion expense on the liabilities for nuclear waste management and decommissioning and the earnings on the associated segregated funds (see Ex. C2-1-1) from the regulated earnings before tax. These reconciling items are consistent with previous applications.

A reconciliation of the segmented balance sheet items for the Regulated – Nuclear Generation and Regulated – Hydroelectric Generation segments as reported in OPG's most recent audited consolidated financial statements (for the year 2024) and the corresponding net plant and other balances forming part of historical rate base values for the prescribed facilities presented in this Application can be found in Ex. B3-3-1,Table 1a and B2-3-1 Table 2a, respectively. The main reconciling items for the Regulated – Nuclear Generation relate to the exclusion of assets related to facilities on lease to Bruce Power LP from rate base (see Ex. G2-2-1). These reconciling items are consistent with previous applications.

LIST OF ATTACHMENTS

Attachment 1:	OPG's 2025 Third Quarter Interim Consolidated Financial Statements (unaudited) and Management's Discussion and Analysis
Attachment 2:	OPG's 2025 Second Quarter Interim Consolidated Financial Statements (unaudited) and Management's Discussion and Analysis
Attachment 3:	OPG's 2025 First Quarter Interim Consolidated Financial Statements (unaudited) and Management's Discussion and Analysis
Attachment 4:	OPG's 2024 Audited Annual Consolidated Financial Statements and Management's Discussion and Analysis

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News
from Ontario Power Generation

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November 11, 2025

OPG Reports 2025 Third Quarter Financial Results

OPG secures historic 20-year nuclear operating licence renewal; Darlington Refurbishment nears finish line ahead of schedule; Company establishes landmark funding for major capital projects

Oshawa, ON – Ontario Power Generation Inc. (OPG or Company) today reported its financial and operating results for the third quarter of 2025, with net income attributable to the Shareholder of $482 million, compared to $379 million for the same period last year. Net income attributable to the Shareholder was $1,528 million for the nine months ended September 30, 2025, compared to $760 million for the same period in 2024.

Darlington Operating Licence Renewal and Darlington Refurbishment Update

In September 2025, the Canadian Nuclear Safety Commission (CNSC) announced its decision to renew OPG's licence to operate the Darlington nuclear generating station (Darlington GS) for a 20-year term – the longest nuclear operating licence ever granted in Canada.

"The station's strong performance, the proficiency of our highly skilled workers, and OPG's continued commitment to safety and operational excellence all played a role in this achievement," said Nicolle Butcher, OPG President and CEO. "With Darlington's refurbishment nearing completion, we look forward to reliable continued operation of the station, through this licence term and beyond."

The Darlington Refurbishment Project is progressing toward completion in the first half of 2026, ahead of its originally scheduled completion in late 2026 and expected to be within budget.

"With the finish line in sight, we are poised to complete this project ahead of schedule and within budget," said Butcher. "This will serve as a blueprint for OPG's future projects, including deploying a fleet of small modular reactors (SMRs) at the Darlington New Nuclear Project (DNNP) site, and refurbishing the Pickering nuclear generating station (Pickering GS), if approved."

Financing Our Growth

OPG remains committed to supporting the provincial and federal efforts to ensure sustainable economic growth and long-term energy security. As it advances its planned and ongoing large-scale capital projects, OPG has made progress in securing diverse sources of financing, alongside government support through financial policy tools that will benefit ratepayers.

As announced on October 23, 2025, OPG has secured up to $3 billion in equity financing for the four-SMR DNNP – up to $1 billion from the Building Ontario Fund and up to $2 billion through the Canada Growth Fund, subject to the satisfaction of conditions – putting Ontario innovation on the global map and contributing to a long-term clean electricity future that will support economic wellbeing and energy security for Canadians.

The Government of Canada's recent reintroduction of the Clean Electricity Investment Tax Credit marks a significant milestone for OPG. This 15 per cent refundable tax credit will provide substantial financial support for federally tax-exempt entities like OPG. This incentive is expected to further strengthen OPG's ability to invest in clean electricity projects, reducing ratepayers' costs and helping to meet Ontario's increasing electricity demand.

"We are focused on our ongoing operations in Ontario, and on meeting growing demand for low-carbon energy," said Butcher. "We continue to execute on a long-term financing path that will assist in meeting capital requirements for our project initiatives right here at home – nuclear and hydroelectric refurbishments, building new generation including the DNNP, and exploring new nuclear potential in Port Hope – so we can continue to power Ontario, and benefit our economy and supply chains."

Port Hope Nuclear Discovery Centre

In October 2025, OPG opened the Port Hope Nuclear Discovery Centre – a new hub for learning, exploration, and community engagement related to potential new nuclear generation at the Wesleyville site.

The opening of the Centre is the next step in the exploration process, which OPG has been undertaking since the Michi Saagiig of the Williams Treaties First Nations signaled their willingness to enter into discussions on the potential for large-scale new nuclear generation at the Wesleyville site, and the Municipality of Port Hope issued a formal expression of interest.

"Over the past several months, we have been actively engaging with residents, stakeholders, Rightsholders, and the public about the potential for new nuclear generation at the Wesleyville site," said Butcher. "This space will serve as another venue for community members and Indigenous Nations to access up-to-date information, participate in activities, and share their feedback."

Chenaux Generating Station Anniversary

Over the next two decades, OPG will continue to invest in its existing hydroelectric assets across the province to ensure reliable and efficient operations and increase production of renewable energy. These opportunities include station refurbishments to modernize facility infrastructure, improve existing generating capacity, uncover additional

efficiencies, and, in some cases, redevelop an entire site. Many of OPG's hydroelectric assets have already served Ontarians for decades, including the Chenaux generating station on the Ottawa River, which recently celebrated its 75th anniversary by opening its doors for a well-attended community open house.

"Our hydroelectric stations – like Chenaux – have reliably stood the test of time, generating electricity for Ontarians for decades, with regular maintenance, upkeep and investment," said Butcher. "As we advance investments across our hydro fleet, we can be confident these clean power workhorses will continue to affordably serve Ontarians for decades to come."

Third quarter highlights include:

Net Income attributable to the Shareholder

Net income attributable to the Shareholder for the three and nine month periods ended September 30, 2025 was $482 million and $1,528 million, respectively, representing an increase of $103 million and $768 million compared to the same periods in 2024. The increases for both periods were primarily attributable to higher earnings from the Regulated – Nuclear Generation business segment, reflecting lower operating, maintenance and administration expenses, mainly due to fewer planned cyclical outage activities and the cessation of commercial operation of Unit 1 and Unit 4 of the Pickering GS in the fourth quarter of 2024 and, for the nine months ended September 30, 2025, higher revenue as a result of higher nuclear electricity generation.

Generating and Operating Performance

Electricity generated was 22.3 terawatt hours (TWh) and 67.7 TWh for the three and nine month periods ended September 30, 2025, respectively, compared to 21.7 TWh and 61.7 TWh for the same periods in 2024.

Regulated – Nuclear Generation Segment

Electricity generation from the Regulated – Nuclear Generation business segment increased by 0.3 TWh and 4.7 TWh for the three and nine month periods ended September 30, 2025, respectively, compared to the same periods in 2024. The increases in both periods were primarily due to electricity generation from Unit 1 of the Darlington GS following its return to service from refurbishment in November 2024 and fewer planned outage days at the Darlington GS and the Pickering GS, partially offset by reduced electricity generation resulting from the cessation of commercial operation of Unit 1 and Unit 4 of the Pickering GS in the fourth quarter of 2024.

The Darlington GS unit capability factor increased to 99.5 per cent and 98.9 per cent for the three and nine month periods ended September 30, 2025, respectively, compared to 94.8 per cent and 74.8 per cent for the same periods in 2024.

The Pickering GS unit capability factor increased to 94.9 per cent and 94.5 per cent for the three and nine month periods ended September 30, 2025, respectively, compared to 91.5 per cent and 82.9 per cent for the same periods in 2024.

The increases in the unit capability factors in both periods were due to fewer planned and unplanned outage days at each generating station.

Regulated – Hydroelectric Generation Segment

Electricity generation from the Regulated – Hydroelectric Generation business segment decreased by 0.6 TWh and 0.5 TWh for the three and nine month periods ended September 30, 2025, respectively, compared to the same periods in 2024, primarily due to lower water inflow conditions across most of Ontario during the third quarter of 2025.

Availability at the regulated hydroelectric stations increased to 85.7 per cent and 86.5 per cent for the three and nine month periods ended September 30, 2025, respectively, compared to 81.5 per cent and 86.3 per cent for the same periods in 2024. The increase for the three months ended September 30, 2025 was primarily due to fewer planned outages across the regulated hydroelectric fleet. Hydroelectric Availability for the nine months ended September 30, 2025 was comparable to the same period in 2024.

Contracted Hydroelectric and Other Generation Segment

Electricity generation from the Contracted Hydroelectric and Other Generation business segment increased by 0.4 TWh and 0.7 TWh for the three and nine month periods ended September 30, 2025, respectively, compared to the same periods in 2024, primarily due to higher water flows across the contracted hydroelectric facilities in northeastern Ontario during the second and third quarters of 2025.

Availability of the hydroelectric stations in the business segment increased to 89.0 per cent and to 85.2 per cent for the three and nine month periods ended September 30, 2025, respectively, compared to 79.0 per cent and 82.4 per cent for the same periods in 2024. The increases for the three and nine month periods ended September 30, 2025, compared to the same periods in 2024, were primarily due to fewer planned outages at the Lower Mattagami hydroelectric generating stations.

Atura Power Segment

Electricity generation from the Atura Power business segment increased by 0.5 TWh and 1.1 TWh for the three and nine month periods ended September 30, 2025, compared to the same periods in 2024, primarily due to higher demand for electricity generation from the combined cycle plants.

Thermal Availability of the generating stations in the segment increased to 88.2 per cent as at September 30, 2025, compared to 87.7 per cent as at September 30, 2024, primarily due to fewer planned and unplanned outages at the Halton Hills and Napanee generating stations.

Generation Development

The Company is undertaking a number of generation development and other projects to maximize the value of and expand its generating fleet in support of Ontario's electricity system.

Darlington Refurbishment Project

On August 20, 2025, the Unit 4 refurbishment at the Darlington GS completed the third major segment, Reassembly, which involved the installation and reassembly of reactor components, including new feeder tubes and fuel channel assemblies.

The Power Up segment, which involves loading new fuel into the reactor, restoring the reactor vault, reconnecting the unit to the rest of the station, and returning the unit to service, commenced following the completion of the Reassembly segment, with the loading of new fuel into the reactor completed in September 2025. The project is currently working to restore the reactor vault, which includes removing the bulkheads to reconnect Unit 4 back to the operating units.

The total project costs, including the impacts of the COVID-19 pandemic and inflation, are tracking within the $12.8 billion budget.

Darlington New Nuclear Project

Following the CNSC's approval of the licence to construct and the Province of Ontario's approval to proceed, OPG is advancing the execution phase of the first SMR at the DNNP site. OPG expects to complete the construction of the first SMR by the end of the decade and connect it to the electricity grid by the end of 2030. The total budget for the first SMR, including infrastructure that would be common for all four planned SMRs at the site, is $7.7 billion.

During the third quarter of 2025, the project completed the foundation work for the radiation waste, control and service buildings. OPG also completed the construction of the on-site pre-assembly building, which will support the final assembly of reactor building structural components for the first SMR.

OPG also continues to advance planning and licensing activities for the three additional SMRs, with site grading activities completed in July 2025. Pending provincial and regulatory approvals for the construction of these additional SMRs, the DNNP's total generating capacity is expected to reach approximately 1,200 MW.

Further details on OPG's major projects can be found in Management's Discussion and Analysis as at and for the three and nine month periods ended September 30, 2025, section, *Core Business and Outlook* under the heading, *Project Excellence*.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(millions of dollars – except where noted)	Three Months Ended September 30		Nine Months Ended September 30	
	2025	**2024**	**2025**	**2024**
Revenue	**2,066**	1,891	**6,255**	5,349
Fuel expense	**369**	267	**1,025**	760
Operations, maintenance and administration expenses	**661**	775	**2,032**	2,485
Depreciation and amortization expenses	**360**	331	**1,070**	935
Accretion on fixed asset removal and nuclear waste management liabilities	**310**	303	**934**	914
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(284)**	(277)	**(848)**	(822)
Other net expenses (gains)	**10**	(11)	**10**	31
Earnings before interest and income taxes	**640**	503	**2,032**	1,046
Net interest expense	**40**	48	**148**	144
Income tax expense	**114**	72	**342**	128
Net income	**486**	383	**1,542**	774
Net income attributable to the Shareholder	**482**	379	**1,528**	760
Net income attributable to non-controlling interest [1]	**4**	4	**14**	14
Earnings (loss) before interest and income taxes				
Electricity generating business segments	**660**	499	**2,069**	1,102
Regulated – Nuclear Sustainability Services	**(23)**	(24)	**(77)**	(84)
Other	**3**	28	**40**	28
Earnings before interest and income taxes	**640**	503	**2,032**	1,046
Cash flow provided by operating activities	**1,461**	746	**3,090**	1,782
Capital expenditures [2]	**1,362**	908	**4,204**	2,627
Electricity generation (TWh)				
Regulated – Nuclear Generation	**9.8**	9.5	**29.4**	24.7
Regulated – Hydroelectric Generation	**7.2**	7.8	**24.1**	24.6
Contracted Hydroelectric and Other Generation [3]	**1.2**	0.8	**4.5**	3.8
Atura Power	**4.1**	3.6	**9.7**	8.6
Total OPG electricity generation	**22.3**	21.7	**67.7**	61.7
Nuclear unit capability factor (per cent) [4]				
Darlington Nuclear GS	**99.5**	94.8	**98.9**	74.8
Pickering Nuclear GS	**94.9**	91.5	**94.5**	82.9
Availability (per cent)				
Regulated – Hydroelectric Generation	**85.7**	81.5	**86.5**	86.3
Contracted Hydroelectric and Other Generation – hydroelectric stations	**89.0**	79.0	**85.2**	82.4
Atura Power [5]	**88.2**	87.7	**88.2**	87.7

[1] Relates to the following: 25 per cent interest of Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in Lower Mattagami Limited Partnership; 33 per cent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in PSS Generating Station Limited Partnership; 15 per cent and 5 per cent interests of corporations wholly owned by Six Nations of Grand River Development Corporation and the Mississaugas of the Credit First Nation, respectively, in Nanticoke Solar LP; and non-controlling interests in certain electricity generating facilities in the United States.

[2] Includes net changes in accruals.

[3] Includes OPG's proportionate share of electricity generation from co-owned and minority shareholdings in electricity generating facilities.

[4] Excludes nuclear unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 1 of the Darlington GS was excluded from the reported planned and unplanned outage days during its refurbishment period of February 15, 2022 to November 27, 2024 and Unit 4 of the Darlington GS has been excluded from the measure since commencing refurbishment on July 19, 2023.

[5] Reflects the thermal availability of combined cycle plants as at the period end date, calculated on a three-year rolling average basis.

About OPG

As Ontario's largest and one of North America's most diverse electricity generators, OPG invests in local economies and employs thousands of people across Ontario. OPG and its family of companies are advancing the development of new low-carbon technologies, refurbishment projects and electrification initiatives to power the growing demands of a clean economy. Learn more about how the company is delivering these initiatives while prioritizing people, partnerships and strong communities at www.opg.com.

Ontario Power Generation Inc.'s unaudited interim consolidated financial statements and Management's Discussion and Analysis as at and for the three and nine month periods ended September 30, 2025, can be accessed on OPG's web site (www.opg.com), the Canadian Securities Administrators' web site (www.sedarplus.com), or can be requested from the Company.

For further information, please contact:

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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2025 THIRD QUARTER REPORT

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ONTARIO POWER GENERATION

ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. and its subsidiaries (OPG or Company) as at and for the three and nine month periods ended September 30, 2025. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars, unless otherwise noted.

For a complete description of OPG's corporate strategies, risk management, corporate governance, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, Annual Information Form, and MD&A as at and for the year ended December 31, 2024.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG has also received exemptive relief from the Ontario Securities Commission (OSC) that allows OPG to apply US GAAP instead of International Financial Reporting Standards (IFRS). In September 2022, the OSC approved an exemption which allows the Company to continue to apply US GAAP up to January 1, 2027. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2027. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP*, in OPG's 2024 annual MD&A. This MD&A is dated November 11, 2025.

Additional information about OPG, including the Company's Annual Information Form, is available on SEDAR+ at www.sedarplus.com and the Company's website at www.opg.com.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "budget", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could" and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks and uncertainties, including those set out in the section, *Risk Management*, and forecasts discussed in the section, *Core Business and Outlook*. All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station (GS) performance, availability and operating lives, fuel costs, surplus baseload generation (SBG), fixed asset removal and nuclear waste management obligations and costs, availability of facilities for the permanent disposal of used nuclear fuel and other nuclear waste, performance and earnings of segregated nuclear and OPG pension funds, refurbishment of existing facilities, development and construction of new facilities, acquisition transactions and other business expansion opportunities, performance of acquired businesses, divestiture transactions including timing and satisfaction of closing conditions, defined benefit pension and other post-employment benefit (OPEB) obligations and costs, income taxes, proposed new legislation, government policy including tariffs and the trade environment, the ongoing evolution and growth of electricity industries and markets in Ontario, Canada and the United States of America (United States or US), the continued application and renewal of energy supply agreements (ESAs) with the Independent Electricity System Operator (IESO) and other contracts for non-regulated facilities, inflation, interest rates, foreign currency exchange rates, commodity prices, wholesale electricity market prices, environmental and other regulatory requirements, operating licence applications to the Canadian Nuclear Safety Commission (CNSC) and the Federal Energy Regulatory Commission (FERC), health, safety and environmental developments, changes in the Company's workforce, renewal of union collective agreements, business continuity events, the weather, climate change, technological change, geopolitical events, financing requirements and liquidity, funding sources, applications to the Ontario Energy Board (OEB) for regulated prices, the impact of regulatory decisions by the OEB, clean energy investment government programs, forecasts of earnings, cash flow, earnings before interest, income taxes, depreciation and amortization, gross margin, operations, maintenance and administration (OM&A) expenses and project and other expenditures, retention of critical talent, supply chain availability and capacity, and supplier and third party performance. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events or otherwise.

Use of Non-GAAP Financial Measures

The Company uses the following non-GAAP financial performance measures in the MD&A:

- "Earnings before Interest, Income Taxes, Depreciation and Amortization"; and
- "Gross Margin".

For a detailed description of each of the non-GAAP measures used in this MD&A, refer to the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*. The non-GAAP financial performance measures set out in this MD&A are intended to provide additional information to investors and do not have any standardized meaning under US GAAP, and therefore may not be comparable to other issuers, and should not be considered in isolation or as a substitute for measures of performance prepared under US GAAP.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at September 30, 2025, OPG owned and operated two nuclear generating stations, 66 hydroelectric generating stations, two thermal generating stations, one solar facility and four combined-cycle gas turbine (combined cycle) plants in Ontario, Canada. The combined cycle plants are natural gas-fired facilities owned and operated through the Company's wholly-owned subsidiary operating as Atura Power. Through its US-based wholly-owned subsidiary, OPG Eagle Creek Holdings LLC (Eagle Creek), OPG also wholly or jointly owned and operated 85 hydroelectric generating stations and held minority interests in 14 hydroelectric and two solar facilities in the US as at September 30, 2025 . In addition, OPG owned two nuclear generating stations in Ontario, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to, and operated by, Bruce Power L.P. (Bruce Power).

In October 2025, OPG entered into an agreement to sell Eagle Creek's electricity generation and development business in the US. Further details on the transaction can be found in the section, *Significant Developments* under the heading, *Financial Strength – Agreement to Sell US Electricity Generation Operations*.

Reporting Structure

The composition of OPG's reportable business segments effective as at September 30, 2025 was as follows:

- Regulated – Nuclear Generation;
- Regulated – Nuclear Sustainability Services;
- Regulated – Hydroelectric Generation;
- Contracted Hydroelectric and Other Generation; and
- Atura Power.

Income from the generating stations leased to Bruce Power is included in revenue under the Regulated – Nuclear Generation business segment. The leased stations are not included in the Company's electricity generation and other operating statistics set out in this MD&A.

Trends

OPG's quarterly electricity generation and the financial results of the Regulated – Nuclear Generation business segment are primarily impacted by maintenance outage cycles, unplanned outage activities and timing of refurbishment activities at the nuclear generating stations, which may result in period-over-period variability in OPG's financial results. The maintenance outage cycle at each of OPG's nuclear generating stations determines the number of planned outages in a particular year. Outage cycles are designed to ensure continued safe and reliable long-term operations of the stations and their compliance with the CNSC's regulatory requirements.

The Darlington and Pickering nuclear generating stations have been designed to operate at full power as baseload generating facilities and therefore their electricity production does not vary with changes in grid-supplied electricity demand.

OPG's quarterly electricity generation from the Regulated – Hydroelectric Generation, Contracted Hydroelectric and Other Generation, and Atura Power business segments is affected by changes in grid-supplied electricity demand. Changes in grid-supplied electricity demand are primarily caused by variations in seasonal weather conditions, changes in economic conditions, the impact of small-scale generation embedded in distribution networks, and the impact of conservation efforts. Historically, there has been greater electricity demand in Ontario during the winter and summer months due to heating and air conditioning demands. The financial impact of forgone hydroelectric electricity generation from the Regulated – Hydroelectric Generation business segment due to SBG conditions is mitigated by a regulatory variance account authorized by the OEB.

OPG's quarterly electricity generation from hydroelectric facilities is impacted by weather conditions that affect water flows. Historically, there have been higher water flows in the second quarter as a result of snow and ice melt entering the river systems. The financial impact of variability in water flows on the Regulated – Hydroelectric Generation business segment is mitigated by a regulatory variance account authorized by the OEB.

The financial impact of variability in electricity generation from the Contracted Hydroelectric and Other Generation business segment and the Atura Power business segment is mitigated by the terms of the applicable ESAs with the IESO for the contracted generating facilities in Ontario.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as at September 30, 2025 and December 31, 2024 was as follows:

	As At	
(MW)	**September 30 2025**	**December 31 2024**
Regulated – Nuclear Generation [1]	**4,698**	4,698
Regulated – Hydroelectric Generation [2]	**6,566**	6,566
Contracted Hydroelectric and Other Generation [2, 3]	**4,080**	4,080
Atura Power	**2,750**	2,715
Total [4]	**18,094**	18,059

[1] The in-service generating capacity as at September 30, 2025 and December 31, 2024 excludes Unit 4 of the Darlington GS. Unit 4 was taken offline for refurbishment in July 2023 and has a generating capacity of 878 MW. As at September 30, 2025 and December 31, 2024, the Darlington GS had three units in service and the Pickering GS had four units in service.

[2] In-service generating capacity is initially based on estimates at the time of asset in-service. The final capacity may differ once required engineering assessments have been completed and verified.

[3] Includes OPG's proportionate share of in-service generating capacity from co-owned and minority shareholdings in electricity generating facilities.

[4] In-service generating capacity represents the portion of installed capacity (the highest level of MW output which a generating unit can maintain indefinitely under reference conditions, without damage to the unit) that has not been removed from service. The Bruce Power leased stations are excluded from electricity generation and operating statistics set out in this MD&A.

The total in-service generating capacity as at September 30, 2025 increased by 35 megawatts (MW) compared to December 31, 2024. The increase was due to the completion of the contractual generating capacity upgrades at the Halton Hills GS in the first quarter of 2025, as previously awarded by the IESO.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results for the three and nine month periods ended September 30, 2025, compared to the same periods in 2024. A discussion of OPG's performance by business segment can be found in the section, *Discussion of Operating Results by Business Segment*.

(millions of dollars – except where noted)	Three Months Ended September 30 2025	2024	Nine Months Ended September 30 2025	2024
Revenue	**2,066**	1,891	**6,255**	5,349
Fuel expense	**369**	267	**1,025**	760
Operations, maintenance and administration expenses	**661**	775	**2,032**	2,485
Depreciation and amortization expenses	**360**	331	**1,070**	935
Accretion on fixed asset removal and nuclear waste management liabilities	**310**	303	**934**	914
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(284)**	(277)	**(848)**	(822)
Other net expenses (gains)	**10**	(11)	**10**	31
Earnings before interest and income taxes	**640**	503	**2,032**	1,046
Net interest expense	**40**	48	**148**	144
Income tax expense	**114**	72	**342**	128
Net income	**486**	383	**1,542**	774
Net income attributable to the Shareholder	**482**	379	**1,528**	760
Net income attributable to non-controlling interest [1]	**4**	4	**14**	14
Electricity generation (TWh) [2]	**22.3**	21.7	**67.7**	61.7
Cash flow provided by operating activities	**1,461**	746	**3,090**	1,782
Capital expenditures [3]	**1,362**	908	**4,204**	2,627
Earnings (loss) before interest and income taxes by segment				
Regulated – Nuclear Generation	**392**	241	**1,147**	245
Regulated – Hydroelectric Generation	**113**	120	**439**	446
Contracted Hydroelectric and Other Generation [4]	**79**	54	**267**	197
Atura Power	**76**	84	**216**	214
Total electricity generating business segments	**660**	499	**2,069**	1,102
Regulated – Nuclear Sustainability Services	**(23)**	(24)	**(77)**	(84)
Other	**3**	28	**40**	28
Earnings before interest and income taxes	**640**	503	**2,032**	1,046

[1] Relates to the following: 25 percent interest of Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in Lower Mattagami Limited Partnership; 33 percent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in PSS Generating Station Limited Partnership; 15 percent interest and 5 percent interest of corporations wholly owned by Six Nations of Grand River Development Corporation and the Mississaugas of the Credit First Nation, respectively, in Nanticoke Solar LP; and non-controlling interests in certain electricity generating facilities in the US.
[2] Includes OPG's proportionate share of electricity generation from co-owned and minority-held facilities.
[3] Includes net changes in accruals.
[4] Includes contracted revenue from hydroelectric generating stations in Ontario operating under ESAs, with expiration dates ranging from 2059 to 2067.

Third Quarter

Net income attributable to the Shareholder was $482 million for the third quarter of 2025, representing an increase of $103 million compared to the same period in 2024.

Earnings before interest and income taxes (EBIT) were $640 million for the third quarter of 2025, representing an increase of $137 million compared to the same period in 2024.

Significant factor that increased EBIT:

- Lower OM&A expenses of $130 million from the Regulated – Nuclear Generation business segment, primarily due to higher amounts of OM&A expenses recorded as recoverable from customers through OEB-authorized regulatory deferral and variance accounts (regulatory accounts) in the third quarter of 2025, lower expenditures related to the cyclical maintenance activities as a result of fewer planned outage days at both the Darlington nuclear generating station (Darlington GS) and the Pickering nuclear generating station (Pickering GS), and the cessation of commercial operation of Unit 1 and Unit 4 of the Pickering GS in the fourth quarter of 2024.

Significant factor that decreased EBIT:

- A gain of $25 million recorded in the third quarter of 2024 within the Other category related to changes in the market value of non-core equity holdings in a publicly traded company.

Net interest expense decreased by $8 million in the third quarter of 2025, compared to the same period in 2024, primarily due to a higher amount of interest costs capitalized related to increased project expenditures, including the Pickering Refurbishment project and the development of a battery energy storage system at the Napanee GS site (Napanee BESS).

Income tax expense increased by $42 million in the third quarter of 2025, compared to the same period in 2024. The increase was primarily due to the impact of higher earnings before income taxes.

Year-To-Date

Net income attributable to the Shareholder was $1,528 million for the first nine months of 2025, representing an increase of $768 million compared to the same period in 2024.

Earnings before interest and income taxes were $2,032 million for the first nine months of 2025, an increase of $986 million compared to the same period in 2024.

Significant factors that increased EBIT:

- Lower OM&A expenses of $479 million from the Regulated – Nuclear Generation business segment, largely due to lower expenditures related to the cyclical maintenance activities as a result of fewer planned outage days at both the Darlington GS and Pickering GS, and the cessation of commercial operation of Unit 1 and Unit 4 of the Pickering GS in the fourth quarter of 2024; and
- Increase in revenue of $457 million from the Regulated – Nuclear Generation business segment due to higher electricity generation of 4.7 terawatt hours (TWh). The higher electricity generation was primarily driven by the return to service of Unit 1 of the Darlington GS following refurbishment in November 2024 and fewer planned outage days at both the Darlington GS and the Pickering GS, partially offset by the cessation of commercial operation of Unit 1 and Unit 4 of the Pickering GS in the fourth quarter of 2024.

Net interest expense for the nine months ended September 30, 2025 was comparable to the same period in 2024. An increase in the interest expense on the Company's long-term debt due to bond issuances during 2024 and the first quarter of 2025 was largely offset by a higher amount of interest costs capitalized related to increased project expenditures, including the Pickering Refurbishment project and the Darlington New Nuclear Project (DNNP), and a higher amount of interest recorded as recoverable from customers through regulatory accounts.

Income tax expense increased by $214 million for the nine months ended September 30, 2025, compared to the same period in 2024. The increase was primarily due to the impact of higher earnings before income taxes.

Electricity Generation

Electricity generation for the three and nine month periods ended September 30, 2025 and 2024 was as follows:

(TWh)	Three Months Ended September 30		Nine Months Ended September 30	
	2025	**2024**	**2025**	**2024**
Regulated – Nuclear Generation	**9.8**	9.5	**29.4**	24.7
Regulated – Hydroelectric Generation	**7.2**	7.8	**24.1**	24.6
Contracted Hydroelectric and Other Generation [1]	**1.2**	0.8	**4.5**	3.8
Atura Power	**4.1**	3.6	**9.7**	8.6
Total OPG electricity generation	**22.3**	21.7	**67.7**	61.7

[1] Includes OPG's proportionate share of electricity generation from co-owned and minority shareholdings in electricity generating facilities.

Total OPG electricity generation increased by 0.6 TWh and 6.0 TWh for the three and nine month periods ended September 30, 2025, respectively, compared to the same periods in 2024.

Electricity generation from the Regulated – Nuclear Generation business segment increased by 0.3 TWh and 4.7 TWh for the three and nine month periods ended September 30, 2025, respectively, compared to the same periods in 2024. The increases in both periods were primarily due to electricity generation from Unit 1 of the Darlington GS following its return to service from refurbishment in November 2024 and fewer planned outage days at both the Darlington GS and the Pickering GS. The increases were partially offset by reduced electricity generation resulting from the cessation of commercial operation of Unit 1 and Unit 4 of the Pickering GS in the fourth quarter of 2024.

Electricity generation from the Regulated – Hydroelectric Generation business segment decreased by 0.6 TWh and 0.5 TWh for the three and nine month periods ended September 30, 2025, respectively, compared to the same periods in 2024, primarily due to lower water inflow conditions across most of Ontario during the third quarter of 2025.

Electricity generation from the Contracted Hydroelectric and Other Generation business segment increased by 0.4 TWh and 0.7 TWh for the three and nine month periods ended September 30, 2025, respectively, compared to the same periods in 2024, primarily due to higher water flows across the contracted hydroelectric facilities in northeastern Ontario during the second and third quarters of 2025.

Electricity generation from the Atura Power business segment increased by 0.5 TWh and 1.1 TWh for the three and nine month periods ended September 30, 2025, respectively, compared to the same periods in 2024, primarily due to higher demand for electricity generation from the combined cycle plants.

Ontario's electricity demand as reported by the IESO for the three and nine month periods ended September 30, 2025, excluding electricity exports out of the province, was 37.9 TWh and 108.9 TWh, respectively, compared to 36.9 TWh and 105.4 TWh for the same periods in 2024.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric and certain nuclear generating stations, and other grid-connected renewable resources. Baseload generation surplus in Ontario was higher in the three and nine month periods ended September 30, 2025, compared to the same periods in 2024. Production forgone at OPG's regulated hydroelectric stations due to SBG conditions was 0.1 TWh and 0.7 TWh for the three and nine month periods ended September 30, 2025, respectively, compared to nil and 0.3 TWh for the same periods in 2024. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear generating stations due to SBG conditions.

Cash Flow from Operations

Cash flow provided by operating activities was $1,461 million and $3,090 million for the three and nine month periods ended September 30, 2025, respectively, compared to $746 million and $1,782 million for the same periods in 2024.

The increase for the three months ended September 30, 2025 was primarily driven by higher reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management from the nuclear fixed asset removal and nuclear waste management segregated funds (Nuclear Segregated Funds) and higher revenue receipts from the Regulated – Nuclear Generation business segment. The increase for the nine months ended September 30, 2025 was primarily due to higher revenue receipts from the Regulated – Nuclear Generation business segment and lower income tax installment payments.

Capital Expenditures

Capital expenditures for the three and nine month periods ended September 30, 2025 and 2024 were as follows:

(millions of dollars)	Three Months Ended September 30 2025	2024	Nine Months Ended September 30 2025	2024
Regulated – Nuclear Generation – Darlington Refurbishment	**149**	255	**556**	748
Regulated – Nuclear Generation – Pickering Refurbishment	**361**	91	**1,053**	215
Regulated – Nuclear Generation – DNNP	**288**	141	**703**	381
Regulated – Nuclear Generation – Excluding Darlington Refurbishment, Pickering Refurbishment and DNNP	**154**	145	**398**	492
Regulated – Hydroelectric Generation	**212**	123	**503**	282
Contracted Hydroelectric and Other Generation	**40**	64	**109**	162
Atura Power	**85**	53	**642**	253
Other	**73**	36	**240**	94
Total capital expenditures [1]	**1,362**	908	**4,204**	2,627

[1] Includes net changes in accruals.

Total capital expenditures increased by $454 million and $1,577 million for the three and nine month periods ended September 30, 2025, respectively, compared to the same periods in 2024.

Capital expenditures for the Darlington Refurbishment project decreased by $106 million and $192 million for the three and nine month periods ended September 30, 2025, respectively, compared to the same periods in 2024. The decreases were primarily due to the return to service of Unit 1 of the Darlington GS from refurbishment in November 2024. The decrease for the nine months ended September 30, 2025 was partially offset by higher expenditures on refurbishment activities at Unit 4 of the Darlington GS.

Capital expenditures for the Pickering Refurbishment project increased by $270 million and $838 million for the three and nine month periods ended September 30, 2025, respectively, compared to the same periods in 2024. The increases in both periods were due to higher expenditures on pre-execution refurbishment activities for Units 5 to 8 of the Pickering GS reflecting the project's transition to the definition phase in January 2025.

Capital expenditures for the DNNP increased by $147 million and $322 million for the three and nine month periods ended September 30, 2025, respectively, compared to the same periods in 2024. The increases in both periods were driven by commencement of construction activities for the first small modular reactor (SMR), Unit 1, and infrastructure that would be common for all four planned SMRs at the DNNP site in the second quarter of 2025, as well as higher expenditures for site preparation and other ongoing development activities for the additional three planned SMRs.

Excluding the Darlington Refurbishment project, the Pickering Refurbishment project and the DNNP, capital expenditures for the Regulated – Nuclear Generation business segment decreased by $94 million for the nine months ended September 30, 2025, compared to the same period in 2024. The decrease was primarily due to the completion of the water treatment facility at the Darlington GS in the second quarter of 2024, and the completion of the replacement of primary moisture separators, a component of steam generators, in Unit 1 and Unit 4 of the Darlington GS. Capital expenditures for the three months ended September 30, 2025 were comparable to the same period in 2024.

Capital expenditures for the Regulated – Hydroelectric Generation business segment increased by $89 million and $221 million for the three and nine month periods ended September 30, 2025, respectively, compared to the same periods in 2024. The increases in both periods were primarily due to higher expenditures on the redevelopments of the Kakabeka Falls and several other hydroelectric generating stations as well as the ongoing refurbishment program across the hydroelectric fleet.

Capital expenditures for the Contracted Hydroelectric and Other Generation business segment decreased by $24 million and $53 million for the three and nine month periods ended September 30, 2025, respectively, compared to the same periods in 2024. The decreases in both periods were primarily due to lower expenditures on the Smoky Falls Dam Safety project, and lower expenditures on the Little Long Dam Safety project driven by project closing activities undertaken in the third quarter of 2024.

Capital expenditures for the Atura Power business segment increased by $32 million and $389 million for the three and nine month periods ended September 30, 2025, respectively, compared to the same periods in 2024. The increases in both periods were primarily due to higher expenditures on the development of the Napanee BESS under a long-term agreement with the IESO executed in 2023, higher expenditures for the expansion of the combined cycle plant at the Napanee GS under a long-term agreement with the IESO executed in 2024, and higher expenditures for the advancement of the Niagara Hydrogen Centre, a low-carbon hydrogen development project. The increases in both periods were partially offset by lower expenditures at existing combined cycle plant facilities.

Capital expenditures within the Other category increased by $37 million and $146 million for the three and nine month periods ended September 30, 2025, respectively, compared to the same periods in 2024. The increases in both periods were primarily due to higher expenditures related to the retrofitting and renovation of OPG's new corporate headquarters building in Oshawa, Ontario prior to occupancy in August 2025 and higher expenditures on information technology improvements.

Further details on the Company's major projects can be found in sections, *Core Business and Outlook* under the heading, *Project Excellence,* and *Significant Developments* under the heading, *Project Excellence.*

SIGNIFICANT DEVELOPMENTS

Project Excellence

Darlington Refurbishment

On August 20, 2025, the Unit 4 refurbishment at the Darlington GS completed the third major segment, Reassembly, which involved the installation and reassembly of reactor components, including new feeder tubes and fuel channel assemblies.

The Power Up segment, which involves loading new fuel into the reactor, restoring the reactor vault, reconnecting the unit to the rest of the station, and returning the unit to service, commenced following the completion of the Reassembly segment, with the loading of new fuel into the reactor completed in September 2025. The project is currently working to restore the reactor vault, which includes removing the bulkheads to reconnect Unit 4 back to the operating units. Vault restoration is on track for completion in December 2025. Achievement of this milestone will represent the completion of construction work, full reconnection of Unit 4 to the station, and transition of the unit to start-up activities.

Unit 4 is expected to be safely returned to service in the first half of 2026, ahead of its original schedule, reflecting the benefits and efficiencies from the experience of the completed refurbishments of Unit 2, Unit 3 and Unit 1.

The total project costs, including the impacts of the COVID-19 pandemic, are tracking within the $12.8 billion budget.

Operational Excellence

Darlington Nuclear Operating Licence Renewal

On September 25, 2025, following public hearings held in March 2025 and June 2025, the CNSC announced the renewal of OPG's power reactor operating licence for the Darlington GS for a 20-year period, valid until November 30, 2045, marking the longest operating licence term ever granted to a Canadian nuclear generating station.

Financial Strength

Equity Commitment Agreement for Darlington New Nuclear Project with Building Ontario Fund and Canada Growth Fund

In October 2025, it was announced that OPG has secured up to $3 billion in equity financing for the four-SMR DNNP, up to $1 billion from the Building Ontario Fund (BOF) and up to $2 billion through the Canada Growth Fund (CGF), subject to the satisfaction of certain conditions. OPG will remain the majority owner and operator of the DNNP, with the CGF and BOF acquiring minority equity interests of up to 15 percent and 7.5 percent ownership, respectively. The CGF and BOF's capital will be made available to OPG in two tranches – initial capital funding for Unit 1 and additional capital for the three additional SMRs once the project meets certain milestones.

Federal Clean Electricity Investment Tax Credits

In the federal budget of November 2025, the Government of Canada reiterated its intention to introduce the Clean Electricity Investment Tax Credit (CEITC), which was originally announced as part of the 2023 federal budget. For eligible projects commencing after March 2023, the CEITC provides a 15 percent refundable tax credit on eligible clean electricity investments made after April 16, 2024, by federally tax-exempt entities including OPG. If certain labour conditions are not met, these refundable credits are reduced by 10 percent. These CEITCs will be available for certain clean energy projects up to and including 2034, subject to compliance with certain conditions. Among others, eligible investments in new projects including SMRs and large-scale nuclear reactors, hydroelectric electricity generation, certain stationary electricity storage systems including battery and pumped hydroelectric storage projects, and refurbishment of certain existing facilities could qualify for the CEITC.

Agreement to Sell US Electricity Generation Operations

In October 2025, OPG entered into an agreement to sell Eagle Creek's electricity generation and development business in the US for a consideration of USD $1.48 billion, inclusive of debt to be assumed by the purchaser and subject to working capital and other adjustments that are to be finalized upon the closing of the transaction. The proceeds from the sale will support funding needs for the Company's Ontario-based projects and initiatives with respect to the development and generation of electricity in the province. The closing of the transaction is expected to occur in the first quarter of 2026, and is subject to customary closing conditions including regulatory approvals. Eagle Creek's operating results are reported under the Contracted Hydroelectric and Other Generation business segment.

Social Licence

Port Hope Nuclear Information Centre

With the Michi Saagiig First Nations of the Williams Treaties' willingness to enter discussions and after a formal expression of interest from the Municipality of Port Hope in January 2025 for the potential for new nuclear energy generation at the Wesleyville site. OPG has been working with local communities and First Nations to determine their support for a potential project. In October 2025, OPG announced the opening of the Port Hope Nuclear Discovery Centre, a new hub that aims to provide learning opportunities, foster community engagement, and serve as a venue for residents, stakeholders, and Indigenous Nations to access information, participate in activities, and share feedback related to a potential project. The opening of the centre is the next step in the exploration process for potential new nuclear energy generation at the Wesleyville site and reflects OPG's commitment to working with local communities and First Nations to determine their support.

CORE BUSINESS AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements* at the beginning of the MD&A.

The following sections provide an update to OPG's disclosures in the 2024 annual MD&A related to its four business imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these imperatives as part of OPG's corporate strategy is included in the 2024 annual MD&A in the sections, *The Company* and *Core Business and Outlook.*

Operational Excellence

Electricity Generation Production and Reliability

Nuclear Operations

OPG's plan to optimize the end of operations dates for the Pickering GS includes operating Units 5 to 8 until the end of September 2026, prior to their planned refurbishment. The current CNSC power reactor operating licence for the Pickering GS is valid until August 31, 2028. On June 27, 2025, OPG submitted an application to the CNSC to renew the power reactor operating licence for the Pickering GS for a period of 10 years, inclusive of planned refurbishment activities. The two-part public hearing on the application is scheduled to be held by the CNSC in April 2026 and June 2026.

In January 2025, the Province announced its approval of OPG's plan to proceed with the project definition phase as the next step toward refurbishing Units 5 to 8 of the Pickering GS. The OPG Board of Directors' (Board) approved budget for the project definition phase is $4.1 billion, bringing the total Board-approved budget for the project to date to $6.2 billion. During the definition phase, OPG has been completing a high-quality cost estimate and schedule for the project, furthering procurement and contracting work, continuing to optimize project scope, and developing the project execution plan. The remaining definition phase is expected to last through 2026. Once refurbished, the Pickering GS would continue to provide over 2,000 MW of baseload generating capacity, equivalent to powering approximately two million homes, to help meet Ontario's demand for electricity. The refurbishment of Units 5 to 8 of the Pickering GS is anticipated to be completed by the mid-2030s.

Collective Agreement

The current two-year collective agreement between the Society of United Professionals (Society) and OPG expires on December 31, 2025. Negotiations for the renewal of the collective agreement began in September 2025 and are ongoing. The Society bargaining unit represents over 30 percent of OPG's workforce.

Project Excellence

Darlington New Nuclear Project

OPG continues to advance the DNNP and expects to complete the construction of Canada's first grid-scale SMR by the end of the decade and connect it to the electricity grid by the end of 2030, using the BWRX-300 reactor plant technology.

During the third quarter of 2025, the project completed the foundation work for the radiation waste, control and service buildings. OPG also completed the construction of the on-site pre-assembly building, which will support the final assembly of reactor building structural components for the first SMR. OPG also continues to advance planning and licensing activities for the three additional SMRs, with site grading activities completed in July 2025. Pending Provincial and regulatory approvals for the construction of these additional SMRs, the DNNP's total generating capacity is expected to reach approximately 1,200 MW.

The DNNP is prescribed for rate regulation by the OEB, with the recovery of DNNP costs to be reviewed by the OEB in a future proceeding for OPG's regulated prices. For details on financing developments in support of funding requirements for the project, refer to the section, *Significant Developments* under the heading, *Financial Strength – Equity Commitment Agreement for Darlington New Nuclear Project with Building Ontario Fund and Canada Growth Fund*.

OPG's major projects in the execution phase as at September 30, 2025 are outlined below:

Project	**Capital Expenditures**		**Approved Budget**	**Expected In-service Date**	**Current Status**
(millions of dollars)	**Year-to-date**	**Life-to-date**			
Darlington Refurbishment Project	556	11,746	12,800 [1]	Unit 4 – 2026	The Unit 4 refurbishment is currently in the Power Up segment. The project is expected to be completed in the first half of 2026, ahead of its original schedule, and within budget.
Darlington New Nuclear Project	703	1,674	7,700 [2]	Unit 1 – 2030	The project is advancing the execution phase of the first SMR at the DNNP site. The project is tracking on schedule and on budget.
Redevelopment of Kakabeka Falls Hydroelectric GS	99	138	519	2028	Demolition work has been completed. Major excavation and earthwork construction continues to progress as planned. The project is tracking on schedule and on budget.
Atura Power Development Projects	539	827	1,500 [3]	Niagara Hydrogen Centre – 2026 [4]	Interior equipment installation has been completed, and the building structure is nearing completion for the Niagara Hydrogen Centre. Process piping and electrical installation are in progress. All substation equipment has been installed, and the medium-voltage line installation is underway.
				Napanee BESS – 2026	Site civil work is nearing completion, and substation foundations have been completed for the Napanee BESS project. Battery system connections are underway. The high-voltage transformer has been fully assembled with testing underway.
				Napanee Combined Cycle GS Expansion Project – 2028	All equipment supply contracts have been awarded, and engineering design has been substantially completed for the Napanee Combined Cycle GS Expansion Project. Site construction will commence upon obtaining applicable permits. These projects are tracking on schedule and within the total approved budget.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS. The refurbishments of Units 1 to 3 have been completed. Refurbishment of the four generating units is expected to extend the operating life of the station by at least 30 years.

[2] The approved budget of $7.7 billion includes $6.1 million allocated to Unit 1 and $1.6 billion allocated to systems and services that would be common to all four SMRs planned as part of the project.

[3] The total project budget of approximately $1.5 billion is for the Niagara Hydrogen Centre, the Napanee BESS and the Napanee Combined Cycle GS Expansion projects.

[4] The expected in-service date of the Niagara Hydrogen Centre was previously updated from 2025 to 2026.

Financial Strength

Increasing Revenue, Reducing Costs and Achieving Appropriate Return

In line with its commercial mandate, OPG is focused on increasing revenue and net income, and achieving an appropriate return on the Shareholder's investment, while seeking to minimize the impact on electricity customers through continuous improvement in the Company's cost structure.

For regulated operations, achievement of the above objectives is largely dependent on outcomes of OPG's applications for regulated prices to the OEB and prudent growth of rate base earning a return. Rate base for OPG represents the average net level of investment in regulated fixed and intangible assets in service and an allowance for working capital.

The following table presents the OEB-authorized regulated prices for electricity generated from OPG's regulated facilities in Ontario for the period from January 1, 2024 to December 31, 2026 in effect as of the date of this MD&A:

($/MWh)	**2024**	**2025**	**2026**
Regulated – Nuclear Generation			
Base regulated price [1]	**103.48**	**102.85**	111.33
Deferral and variance account rate riders [2]	**4.28**	**8.76**	12.43
Total regulated price	**107.76**	**111.61**	123.76
Regulated – Hydroelectric Generation			
Base regulated price	**43.88**	**43.88**	43.88
Deferral and variance account rate riders [2]	**3.64**	**3.30**	3.30
Total regulated price	**47.52**	**47.18**	47.18

[1] Base regulated prices for the nuclear facilities were established using a rate smoothing approach that defers a portion of each year's approved nuclear revenue requirement for future collection in the Rate Smoothing Deferral Account. Base regulated prices for the nuclear facilities do not include amounts deferred in the Rate Smoothing Deferral Account.

[2] Deferral and variance account riders reflect the OEB's January 2022 payment amounts order that authorized recovery and repayment of balances recorded in regulatory accounts as at December 31, 2019, and, effective July 2024, the OEB's June 2024 decision and order that authorized recovery and repayment of balances recorded in regulatory accounts as at December 31, 2022.

The base regulated prices for OPG's nuclear electricity generation (nuclear base regulated price) in effect for the period from January 1, 2022 to December 31, 2026 were established by the payment amounts order issued by the OEB in January 2022 reflecting the OEB's decisions on OPG's 2022-2026 rate application issued during the second half of 2021. The nuclear base regulated prices for this period were set on the assumption of the continued operation of Units 5 to 8 of the Pickering GS until the end of 2025, contributing to the higher nuclear base regulated price in 2026. Pursuant to the Pickering B Variance Account (formerly Pickering B Extension Variance Account) established under *Ontario Regulation 53/05* and subject to the OEB's review, OPG will return to ratepayers the additional revenues net of costs associated with operating these units between January 1, 2026 and September 30, 2026.

Pursuant to *Ontario Regulation 53/05*, the base regulated price for OPG's hydroelectric electricity generation (hydroelectric base regulated price) for the period from January 1, 2022 to December 31, 2026 has been set equal to the 2021 hydroelectric base regulated price.

In 2024, the OEB initiated a generic cost of capital proceeding to review the methodology for determining the cost of capital parameters and deemed capital structure used for setting utility rates. As part of its decision issued in March 2025, the OEB updated the cost of capital parameters including the prescribed rate of return on deemed equity applicable to all electricity transmitters, electricity distributors, natural gas utilities, and rate-regulated electricity generators. As a result, the interim prescribed return on a deemed equity portion (ROE) of 9.25 percent applicable to 2025 cost-based rate applications was updated to 9.0 percent on a final basis, effective January 1, 2025. On October 31, 2025, the OEB published a prescribed ROE of 9.11 percent applicable to 2026 cost-based rate applications, effective January 1, 2026. The prescribed ROE will continue to be updated annually through the OEB's ROE adjustment formula. These changes do not affect the prescribed ROE levels or other cost of capital parameters reflected in OPG's previously authorized regulated prices for the period through December 31, 2026. While the OEB did not make changes to deemed capital structures in the generic cost of capital proceeding, it stated that it would consider, on its merits, a proposal by OPG to modify its deemed capital structure, should OPG submit one in its next

application for new regulated prices. For information on OEB-approved cost of capital parameters and rate base levels reflected in OPG's authorized regulated prices through December 31, 2026, refer to OPG's 2024 annual MD&A in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation.*

Effective July 1, 2025, the Province amended *Ontario Regulation 53/05* to clarify the scope of the Pickering B Variance Account such that OPG can record costs incurred on or after January 1, 2024 to preserve the ability to operate Units 5 to 8 of the Pickering GS upon refurbishment for future recovery, subject to review by the OEB. These costs can be recorded in the account until the effective date of the OEB's first order setting nuclear base regulated prices that comes into effect on or after January 1, 2027.

Under the current OEB rate-setting framework, OPG begins recovering costs through regulated prices once projects are placed in-service. In May 2025, the Province proposed potential changes in regulations that would establish a new mechanism for concurrent cost recovery to allow OPG to recover debt interest during the construction periods of the DNNP and the Pickering Refurbishment project (if the project is approved to proceed). The proposed change would also prescribe a new OEB-regulated generator and establish the applicable rate-setting framework to enable OPG to enter into commercial partnerships for the DNNP. The comment period for the proposal ended on June 26, 2025. In conjunction with these proposed regulatory amendments, the Province indicated that it would continue to work with OPG to minimize ratepayer impacts and identify additional sources of cash to ensure sufficient funds are available to finance these projects.

For generation assets that do not form part of the rate regulated operations, OPG generally seeks to secure long-term revenue arrangements that support an appropriate return on the investment. In line with this strategy, all of OPG's non-regulated facilities in Ontario are subject to ESAs with the IESO. These contracts are generally designed to provide for recovery of operating costs and capital investment in the underlying facilities and a return on invested capital, subject to the facilities continuing to meet their contractual obligations.

Ensuring Availability of Cost Effective Funding

OPG actively monitors its funding requirements and forecasts availability of funds to ensure that it can meet the Company's operational needs, project and other commitments, and long-term obligations. In addition to funds generated from operations, OPG currently utilizes the following primary funding sources: commercial paper; letters of credit; credit facilities; public debt offerings; debt sourced from the Ontario Electricity Financial Corporation (OEFC) and Ontario Financing Authority (OFA), agencies of the Province; and private placement and other project financing arrangements.

Credit Ratings

Maintaining an investment grade credit rating supports OPG's ability to access cost effective financing. As at September 30, 2025, the Company's credit ratings were as follows:

Type of Rating	DBRS Limited (DBRS) [1]	S&P Global Ratings (S&P) [2]	Moody's Investors Service (Moody's) [3]
Issuer rating	A (low)	BBB+	A3
Senior unsecured debt	A (low)	BBB+	A3
Trend/Outlook	Stable	Stable	Stable
Commercial paper program – Canada	R-1 (low)	A-1 (low)	NR [4]
Commercial paper program – US	NR [4]	A-2	P-2

[1] In April 2025, DBRS confirmed OPG's A (low) issuer rating, A (low) senior unsecured debt rating and R-1 (low) Canadian commercial paper rating, all with Stable trends.
[2] In August 2024, S&P confirmed OPG's ratings including BBB+ issuer rating with stable outlook, BBB+ senior unsecured debt rating and A-1 (low) Canada commercial paper rating.
[3] In May 2025, Moody's confirmed OPG's A3 issuer rating with stable outlook, A3 senior unsecured debt rating and P-2 US commercial paper rating.
[4] NR indicates no rating assigned.

Additional discussion of the Company's credit facilities and liquidity can be found in the section, *Liquidity and Capital Resources*.

Social Licence

OPG is committed to maintaining high standards of public health and safety and corporate citizenship, including environmental stewardship, transparency, community engagement and Indigenous relations. The Company also strives to be a leader in climate change action, equity, diversity and inclusion (ED&I) practices, and advancing reconciliation with Indigenous peoples.

Further details on social licence activities and initiatives can be found in the section, *Environmental, Social, Governance and Sustainability*.

Outlook

As at September 30, 2025, OPG's capital expenditures for the year 2025 were forecasted at approximately $6 billion, approximately $1 billion higher than previously disclosed in the 2024 annual MD&A. The increase is mainly due to the timing associated with pre-execution phase activities for the planned refurbishment of Units 5 to 8 of the Pickering GS and work advanced across the Atura Power development projects.

OPG's expected net income for 2025 continues to be higher than net income for 2024, taking into consideration the factors discussed in OPG's 2024 annual MD&A in the section, C*ore Business and Outlook* under the heading, *Outlook*.

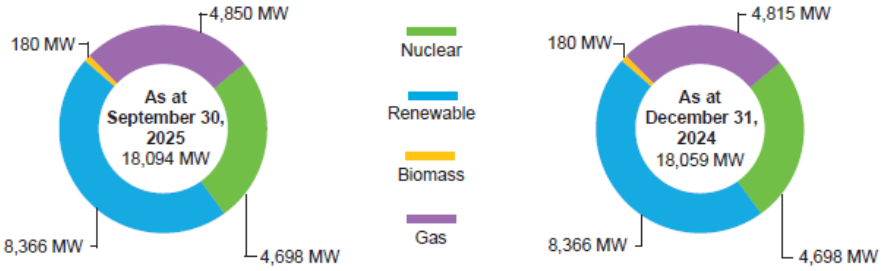
The Company's operating results in 2025 may be impacted by macro-economic factors and geopolitical events, including tariffs and the trade environment, as discussed further in the section, *Risk Management*.

ENVIRONMENTAL, SOCIAL, GOVERNANCE AND SUSTAINABILITY

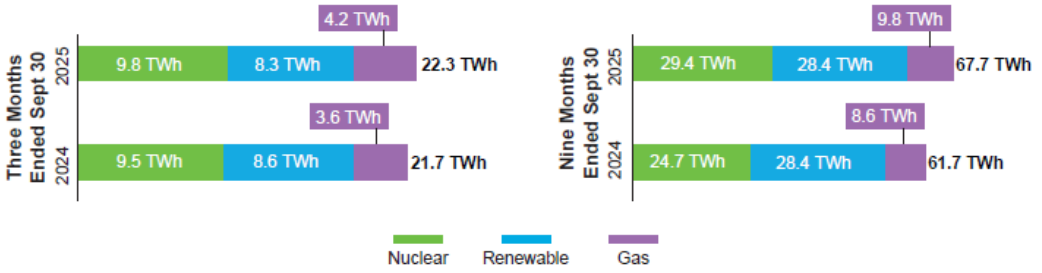
The following sections provide an update to disclosures in the 2024 annual MD&A, related to OPG's social licence activities, sustainability, and environmental, social, governance (ESG) metrics.

Climate-Related Performance and Key Metrics

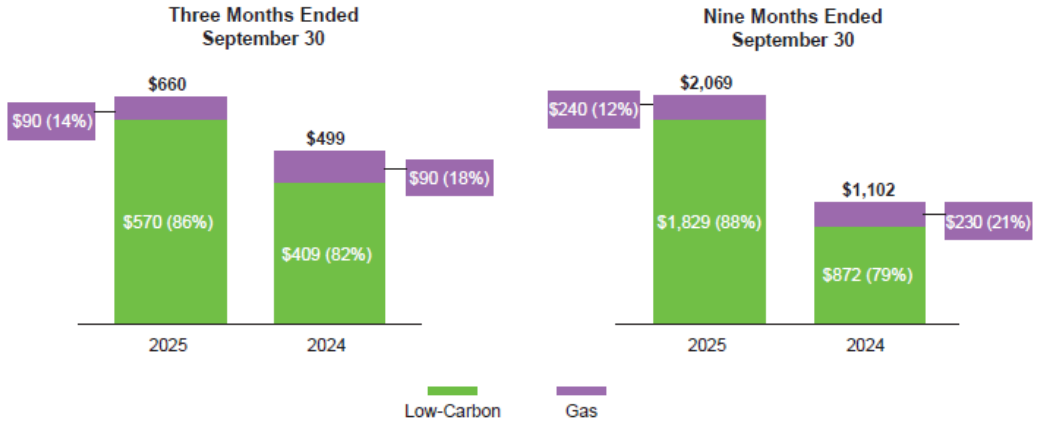
In-service generating capacity by generation type (MW) [1]



Electricity generation by generation type (TWh) [1, 2]



EBIT from generating stations by facility category (millions of dollars); Climate-related transition risk [1]



[1] Includes OPG's proportionate share of in-service generating capacity and electricity generation from co-owned and minority-held facilities. Nuclear generating units undergoing refurbishment are excluded. Gas category includes the dual-fueled Lennox GS and the Company's combined cycle plants operated through Atura Power.

[2] Electricity generated from the Biomass category for the three and nine month periods ended September 30, 2025 represents 0.03 TWh and 0.09 TWh, respectively (three and nine month periods ended September 30, 2024 – 0.03 TWh and 0.06 TWh, respectively).

Climate Change Metrics	
In-service generating capacity by generation type [1]	In-service generating capacity from gas generation sources increased as at September 30, 2025, compared to December 31, 2024, due to the completion of the contractual generating capacity upgrades at the Halton Hills GS in the first quarter of 2025. Low-carbon sources continue to account for the majority of OPG's total in-service generating capacity.
Electricity generation by generation type [1]	Low-carbon sources, which comprise nuclear, renewable and biomass generation, accounted for approximately 81 percent and 85 percent of OPG's total electricity generation during the three and nine month periods ended September 30, 2025, respectively, compared to 83 percent and 86 percent during the same periods in 2024. The decreases in the percentage of generation from low-carbon sources in both periods were primarily due to the increase in electricity generation from the Atura Power business segment. For further details, refer to the section, *Highlights* under the heading, *Electricity Generation*.
EBIT from generating stations by facility category; Climate-related transition risk	The portion of EBIT from low-carbon electricity generation increased during the three and nine month periods ended September 30, 2025, compared to the same periods in 2024, primarily due to higher electricity generation and lower OM&A expenses from the Regulated – Nuclear Generation business segment. For further details, refer to the section, *Discussion of Operating Results by Business Segment* under the heading, *Regulated – Nuclear Generation Segment*.

[1] Identifies capacity available from OPG's different electricity generation sources and tracks low-carbon energy capacity relative to other sources. Nuclear, Renewable (which includes hydroelectric and solar) and Biomass (which uses wood pellets from sustainably managed forests) generation are considered to be low-carbon emitting generation sources.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars – except where noted)	**2025**	**2024**	**2025**	**2024**
Electricity Generation (TWh)	**9.8**	9.5	**29.4**	24.7
Revenue	**1,141**	1,077	**3,415**	2,857
Fuel expense	**92**	72	**253**	216
Gross margin	**1,049**	1,005	**3,162**	2,641
Operations, maintenance and administration expenses	**450**	580	**1,398**	1,877
Property taxes	**6**	6	**19**	19
Other losses	**4**	2	**11**	6
Earnings before interest, income taxes, depreciation and amortization	**589**	417	**1,734**	739
Depreciation and amortization expenses	**197**	176	**587**	494
Earnings before interest and income taxes	**392**	241	**1,147**	245

Earnings before interest and income taxes from the segment increased by $151 million and $902 million for the three and nine month periods ended September 30, 2025, respectively, compared to the same periods in 2024.

The increases in segment earnings in both periods were largely driven by lower OM&A expenses of $130 million and $479 million, respectively and, for the nine months ended September 30, 2025, by higher revenue of $457 million as a result of higher electricity generation of 4.7 TWh. The decrease in OM&A expenses for the three months ended September 30, 2025 was mainly due to higher amounts of expenses recorded as recoverable from customers through regulatory accounts in the third quarter of 2025, lower expenditures related to the cyclical maintenance activities as a result of fewer planned outage days at the Darlington GS and Pickering GS, and the cessation of commercial operation of Unit 1 and Unit 4 of the Pickering GS in the fourth quarter of 2024. The decrease in OM&A expenses for the nine months ended September 30, 2025 was largely due to lower expenditures related to the cyclical maintenance activities as a result of fewer planned outage days at the Darlington GS and Pickering GS, and the cessation of commercial operation of Unit 1 and Unit 4 of the Pickering GS in the fourth quarter of 2024.

The lower depreciation and amortization expenses of $14 million and $51 million for the three and nine month periods ended September 30, 2025, compared to the same periods in 2024, excluding amortization expense related to the recovery and repayment of OEB-authorized regulatory account balances, were primarily due to the cessation of commercial operation of Unit 1 and Unit 4 of the Pickering GS in the fourth quarter of 2024. The decreases were partially offset by higher depreciation expense recognized from placing capital in service, including the return to service of Unit 1 of the Darlington GS following refurbishment in November 2024.

The increase in segment earnings for the nine months ended September 30, 2025, compared to the same period in 2024, was partially offset by a higher amount of $48 million recorded in the second quarter of 2024 as recoverable from customers in the Pickering B Variance Account in connection with forgone electricity generation due to activities associated with the extension of commercial operation of Units 5 to 8 of the Pickering GS to September 2026.

An increase in revenue for the three and nine month periods ended September 30, 2025 reflecting the impact of the new rate riders for disposition of regulatory accounts under the OEB's June 2024 decision and order on OPG's application for such disposition, effective July 1, 2024, was largely offset by a corresponding increase in the amortization expense of regulatory assets and regulatory liabilities recorded for regulatory account balances.

The planned and unplanned outage days at the Darlington and Pickering nuclear generating stations were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2025	**2024**	**2025**	**2024**
Planned Outage Days				
Darlington GS [1]	**-**	4.3	**2.8**	105.2
Pickering GS	**13.5**	32.2	**21.1**	226.7
Unplanned Outage Days				
Darlington GS [1]	**8.3**	12.0	**14.3**	40.8
Pickering GS	**9.9**	25.5	**45.8**	74.3

[1] The planned and unplanned outage days exclude unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 1 of the Darlington GS was excluded from the reported planned and unplanned outage days during its refurbishment period of February 15, 2022 to November 27, 2024 and Unit 4 of the Darlington GS has been excluded from the measure since commencing refurbishment on July 19, 2023.

The lower planned outage days at the Darlington GS for the nine months ended September 30, 2025, compared to the same period in 2024, were driven by the impact of the station's cyclical maintenance outage on the station's Unit 2 during the first half of 2024. Planned outage days at the Darlington GS for the three months ended September 30, 2025 were comparable to the same period in 2024.

The lower planned outage days at the Pickering GS for the three and nine month periods ended September 30, 2025, compared to the same periods in 2024, were driven by the impact of the station's cyclical maintenance schedule and other planned maintenance, inspection and repair work executed at the station during 2024.

The lower unplanned outage days at the Darlington GS for the nine months ended September 30, 2025, compared to the same period in 2024, were primarily driven by steam generator repair activities on the station's Unit 3 in the first half of 2024.

The lower unplanned outage days at the Pickering GS for the three months ended September 30, 2025, compared to the same period in 2024, were primarily due to repair work on the generator system on the station's Unit 5 during the third quarter of 2024. The lower unplanned outage days at the Pickering GS for the nine months ended September 30, 2025, compared to same period in 2024, were primarily due to fuelling machine recovery activities executed at the station in the first half of 2024.

The Unit Capability Factors for the Darlington and Pickering nuclear generating stations were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2025	**2024**	**2025**	**2024**
Unit Capability Factor *(%)* [1, 2]				
Darlington GS	**99.5**	94.8	**98.9**	74.8
Pickering GS	**94.9**	91.5	**94.5**	82.9

[1] Nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment.

[2] Nuclear Unit Capability Factor is defined in the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*.

Regulated – Nuclear Sustainability Services Segment

(millions of dollars – except where noted)	Three Months Ended September 30		Nine Months Ended September 30	
	2025	**2024**	**2025**	**2024**
Revenue	**46**	54	**117**	134
Operations, maintenance and administration expenses	**46**	54	**117**	134
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**307**	301	**925**	906
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(284)**	(277)	**(848)**	(822)
Loss before interest and income taxes	**(23)**	(24)	**(77)**	(84)

The segment loss before interest and income taxes decreased by $1 million and $7 million for the three and nine month periods ended September 30, 2025, respectively, compared to the same periods in 2024. The decrease for the nine months ended September 30, 2025, was primarily due to higher earnings on the Nuclear Segregated Funds, largely offset by higher accretion expense on the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities). The higher accretion expense on the Nuclear Liabilities was due to the increase in the present value of the underlying obligation to reflect the passage of time.

The higher earnings from the Nuclear Segregated Funds were primarily due to the growth in the present value of the underlying funding liabilities per the approved Ontario Nuclear Funds Agreement (ONFA) reference plan in effect. As both the Decommissioning Segregated Fund and the Used Fuel Segregated Fund were in an overfunded position during the three and nine month periods ended September 30, 2025, and during the same periods in 2024, they were not impacted by market returns or the rate of return guarantee provided by the Province for a portion of the Used Fuel Segregated Fund. When both funds are in an overfunded position, OPG limits the amount of Nuclear Segregated Funds assets reported on the consolidated balance sheet to the present value of the underlying funding liabilities per the approved ONFA reference plan in effect. Further details on the accounting for the Nuclear Segregated Funds can be found in OPG's 2024 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds.*

Regulated – Hydroelectric Generation Segment

(millions of dollars – except where noted)	Three Months Ended September 30		Nine Months Ended September 30	
	2025	**2024**	**2025**	**2024**
Electricity generation (TWh)	**7.2**	7.8	**24.1**	24.6
Revenue [1]	**377**	373	**1,216**	1,160
Fuel expense	**86**	83	**249**	241
Gross margin	**291**	290	**967**	919
Operations, maintenance and administration expenses	**109**	102	**319**	306
Property taxes	**1**	-	**1**	1
Other losses	**1**	1	**9**	6
Earnings before interest, income taxes, depreciation and amortization	**180**	187	**638**	606
Depreciation and amortization expenses	**67**	67	**199**	160
Earnings before interest and income taxes	**113**	120	**439**	446

[1] During the three and nine month periods ended September 30, 2025, the Regulated – Hydroelectric Generation business segment revenue included incentive payments of $26 million and $38 million, respectively, related to the OEB-approved hydroelectric incentive mechanism (three and nine month periods ended September 30, 2024 – incentive payments of $11 million and $20 million, respectively). The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

Earnings before interest and income taxes from the segment decreased by $7 million for both the three and nine month periods ended September 30, 2025, compared to the same periods in 2024. The decreases for both periods were mainly due to higher OM&A expenses, driven mainly by increased maintenance activities, and lower revenue as a result of lower electricity generation, partially offset by higher revenue resulting from higher hydroelectric incentive mechanism payments. For the nine months ended September 30, 2025, the lower earnings also reflected higher depreciation and amortization expenses, excluding amortization expenses related to the recovery and repayment of OEB-authorized regulatory account balances, mainly from capital placed in service.

An increase in revenue for the nine months ended September 30, 2025 reflecting the impact of the new rate riders for disposition of regulatory accounts under the OEB's June 2024 decision and order on OPG's application for such disposition, effective July 1, 2024, was largely offset by a corresponding increase in the amortization expense of regulatory assets and regulatory liabilities recorded for regulatory account balances.

The Hydroelectric Availability for the generating stations reported in the Regulated – Hydroelectric Generation business segment was as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2025	**2024**	**2025**	**2024**
Hydroelectric Availability *(%)* [1]	**85.7**	81.5	**86.5**	86.3

[1] Hydroelectric Availability is defined in the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*.

Hydroelectric Availability increased for the three months ended September 30, 2025, compared to the same period in 2024, primarily due to fewer planned outages across the regulated hydroelectric fleet. Hydroelectric Availability for the nine months ended September 30, 2025 was comparable to the same period in 2024.

Contracted Hydroelectric and Other Generation Segment

(millions of dollars – except where noted)	Three Months Ended September 30		Nine Months Ended September 30	
	2025	**2024**	**2025**	**2024**
Electricity generation (TWh)	**1.2**	0.8	**4.5**	3.8
Revenue	**225**	187	**700**	609
Fuel expense	**33**	14	**88**	40
Gross margin	**192**	173	**612**	569
Operations, maintenance and administration expenses	**69**	72	**222**	223
Accretion on fixed asset removal liabilities	**2**	2	**7**	6
Property taxes	**4**	5	**14**	14
Other gains	**(3)**	(1)	**(22)**	(5)
Earnings before interest, income taxes, depreciation and amortization	**120**	95	**391**	331
Depreciation and amortization expenses	**41**	41	**124**	134
Earnings before interest and income taxes	**79**	54	**267**	197

Earnings before interest and income taxes from the segment increased by $25 million and $70 million for the three and nine month periods ended September 30, 2025, respectively, compared to the same periods in 2024.

The increase for the three months ended September 30, 2025 was primarily due to higher earnings from thermal facilities, reflecting higher revenue from the Lennox and Atikokan generating stations, and higher earnings from Ontario-based hydroelectric facilities, driven by higher revenue from the Lower Mattagami generating stations.

The increase for the nine months ended September 30, 2025 was primarily due to higher earnings from the US operations, reflecting higher wholesale electricity market prices and a one-time gain of $18 million recognized in the second quarter of 2025 related to a service contract termination settlement. The increase for the period was also due to higher earnings from thermal facilities, reflecting higher revenue from the Lennox GS and lower depreciation and amortization expense from the Atikokan GS due to the extension of the station's asset life following the amended and restated 5-year term ESA entered into with the IESO in September 2024.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) within the Contracted Hydroelectric and Other Generation segment were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2025	**2024**	**2025**	**2024**
Hydroelectric Availability *(%)* [1, 2]	**89.0**	79.0	**85.2**	82.4
Thermal EFOR *(%)* [2]	**5.2**	6.6	**12.6**	2.8

[1] Hydroelectric Availability reflects the Company's hydroelectric generating stations in Ontario and the United States.
[2] Hydroelectric Availability and Thermal EFOR are defined in the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*.

The Hydroelectric Availability increase for the three and nine month periods ended September 30, 2025, compared to the same periods in 2024, primarily due to fewer planned outages at the Lower Mattagami hydroelectric generating stations.

Thermal EFOR decreased for the three months ended September 30, 2025, compared to the same period in 2024, due to fewer unplanned outage days at the Atikokan GS. Thermal EFOR increased for the nine months ended September 30, 2025, compared to the same period in 2024, due to higher unplanned outage days at the Lennox GS.

Atura Power Segment

(millions of dollars – except where noted)	Three Months Ended September 30		Nine Months Ended September 30	
	2025	**2024**	**2025**	**2024**
Electricity generation (TWh)	**4.1**	3.6	**9.7**	8.6
Revenue	**298**	235	**836**	642
Fuel expense	**158**	98	**435**	263
Gross margin	**140**	137	**401**	379
Operations, maintenance and administration expenses	**27**	23	**80**	73
Accretion on fixed asset removal liabilities	**1**	-	**2**	1
Property taxes	**-**	-	**1**	1
Other losses	**1**	-	**2**	-
Earnings before interest, income taxes, depreciation and amortization	**111**	114	**316**	304
Depreciation and amortization expenses	**35**	30	**100**	90
Earnings before interest and income taxes	**76**	84	**216**	214

Earnings before interest and income taxes from the segment decreased by $8 million for the three months ended September 30, 2025, compared to the same period in 2024. The decrease in earnings was primarily due to higher depreciation and amortization expenses, mainly from capital placed in service, and higher OM&A expenses, mainly driven by increased maintenance activities. Earnings before interest and income taxes from the segment for the nine months ended September 30, 2025 were comparable to the same period in 2024.

The Thermal Availability for the assets within the Atura Power business segment was as follows:

	As At September 30	
	2025	**2024**
Thermal Availability *(%)* [1]	**88.2**	87.7

[1] Thermal Availability is defined in the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*. The measure reflects the availability of the combined cycle plants as at the period end date, calculated on a three-year rolling average basis.

The Thermal Availability for the combined cycle plants increased as at September 30, 2025, compared to September 30, 2024, primarily due to fewer planned and unplanned outages at the Halton Hills GS and Napanee GS.

LIQUIDITY AND CAPITAL RESOURCES

OPG maintains a range of funding sources to ensure sufficient liquidity and meet financing requirements. These sources are used for multiple purposes including: to invest in plants and technologies, undertake major projects and business acquisitions, fund long-term obligations such as contributions to the pension fund, make payments under the OPEB plans, fund expenditures on Nuclear Liabilities not eligible for reimbursement from the Nuclear Segregated Funds, service and repay long-term debt, and provide general working capital. Highlights of OPG's interim consolidated cash flow position are noted below.

Changes in cash and cash equivalents for the three and nine month periods ended September 30, 2025 and 2024 were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2025**	**2024**	**2025**	**2024**
Cash, cash equivalents and restricted cash, beginning of period	**1,823**	1,879	**1,363**	1,481
Cash flow provided by operating activities	**1,461**	746	**3,090**	1,782
Cash flow used in investing activities	**(1,324)**	(883)	**(3,929)**	(2,676)
Cash flow provided by financing activities	**89**	203	**1,532**	1,352
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**3**	(1)	**(4)**	5
Net increase in cash, cash equivalents and restricted cash	**229**	65	**689**	463
Cash, and cash equivalents and restricted cash, end of period	**2,052**	1,944	**2,052**	1,944

For a discussion of cash flow provided by operating activities, refer to the details in the section, *Highlights* under the heading, *Overview of Results.*

Investing Activities

Cash flow used in investing activities for the three and nine month periods ended September 30, 2025 increased by $441 million and $1,253 million, respectively, compared to the same periods in 2024. The increase for the three months ended September 30, 2025 was primarily due to the higher capital expenditures within the Regulated – Nuclear Generation and Regulated – Hydroelectric Generation business segments. The increase for the nine months ended September 30, 2025 was primarily due to the higher capital expenditures within the Regulated – Nuclear Generation, Regulated – Hydroelectric Generation and Atura Power business segments.

Financing Activities

Cash flow provided by financing activities for the three months ended September 30, 2025 decreased by $114 million, compared to the same period in 2024. The decrease was primarily due to the issuance of $300 million green bonds through the Company's Medium Term Note Program during the third quarter of 2024 and higher repayment of long-term debt in the third quarter of 2025, partially offset by higher net issuances of corporate commercial paper during the third quarter of 2025.

Cash flow provided by financing activities for the nine months ended September 30, 2025 increased by $180 million, compared to the same period in 2024. The increase was primarily due to higher net issuances of corporate commercial paper, partially offset by lower net issuances of long-term debt during 2025.

Committed credit facilities as at September 30, 2025 were as follows:

(*millions of dollars*)		**Amount**
Bank facilities:		
Corporate [1, 2]		**1,000**
Corporate [1]	US Dollars	**750**
Lower Mattagami Energy Limited Partnership [3]		**460**
OPG Eagle Creek Holdings LLC and subsidiaries	US Dollars	**20**
Ontario Financing Authority facility [2]		**1,250**
Ontario Electricity Financial Corporation facility [2]		**750**

[1] Certain corporate credit facilities contain a sustainability-linked feature that allows reduced pricing if the Company meets certain sustainability targets.
[2] Represents amounts available under the facility net of debt issuances.
[3] Letter of credit of $65 million was outstanding under this facility as at September 30, 2025.

Short-term debt, letters of credit and guarantees were as follows:

	As At	
(millions of dollars)	**September 30 2025**	**December 31 2024**
Lower Mattagami Energy Limited Partnership	**170**	215
Corporate commercial paper	**1,036**	-
Total short-term debt	**1,206**	215
Letters of credit	**740**	504
Guarantees	**-**	30

As at September 30, 2025, letters of credit issued included $314 million for the supplementary pension plans, $267 million for general corporate purposes, $65 million for Lower Mattagami Energy Limited Partnership, $44 million for Atura Power, $20 million for Eagle Creek and its subsidiaries, $14 million for UMH Energy Partnership, $10 million for Laurentis Energy Partners and its subsidiaries, $5 million for PowerON Energy Solutions LP and $1 million for PSS Generating Station Limited Partnership.

Long-term debt balances were as follows:

	As At	
(millions of dollars)	**September 30 2025**	**December 31 2024**
Medium Term Notes payable	**6,550**	5,950
Senior notes payable under corporate credit facilities	**2,811**	2,859
Project financing	**2,898**	2,916
Other	**25**	25
Total long-term debt [1]	**12,284**	11,750

[1] Excludes the impact of fair value premium or discount and unamortized bond issuance fees.

BALANCE SHEET HIGHLIGHTS

Highlights of OPG's interim consolidated financial position are noted below:

(millions of dollars)	As At September 30 2025	As At December 31 2024
Property, plant and equipment – net The increase was primarily due to capital expenditures, partially offset by depreciation expense. Further details on capital expenditures can be found in the section, *Highlights* under the heading, *Capital Expenditures*.	**39,409**	36,131
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)* The increase was primarily due to earnings recognized on the Nuclear Segregated Funds, partially offset by reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities from the Nuclear Segregated Funds.	**22,694**	22,412
Short-term debt The increase was primarily due to net issuances of corporate commercial paper.	**1,206**	215
Long-term debt *(current and non-current portions)* The increase was due to net issuances under the Company's Medium Term Note Program and corporate credit facilities.	**12,236**	11,707
Fixed asset removal and nuclear waste management liabilities The increase was primarily a result of accretion expense, partially offset by expenditures on fixed asset removal and nuclear waste management activities.	**26,524**	26,042

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's consolidated financial statements or are recorded in the Company's consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to OPG's audited consolidated financial statements as at and for the year ended December 31, 2024. OPG's critical accounting policies are consistent with those noted in OPG's 2024 annual MD&A.

RISK MANAGEMENT

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements* at the beginning of the MD&A. The following section provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2024 annual MD&A in the section, *Risk Management*.

Risks to Achieving Operational Excellence

Tariffs and Trade Environment

Given the highly interconnected nature of the Canadian and US economies, trade and other impacts of tariffs between the two countries could disproportionately impact the Canadian economy. These impacts are expected to increase procurement costs of certain materials for OPG's projects and operations, and may result in supply chain disruptions if there are further restrictions placed on international trade. The economic impacts of the trade disputes could also impact demand for electricity in Ontario. A significant slowing down of the Ontario economy could result in a downward revision to the long-term electricity demand projections. A decrease in the forecasted growth rate of long-term electricity demand may have implications for the future electricity supply mix needed to meet system adequacy requirements, which could impact the potential development of new generation.

The Company continues to actively identify procurements and supplier relationships that are now subject to tariffs, and, where possible, is pursuing alternate suppliers to reduce exposure to tariffs. OPG will continue to monitor changing trade and geopolitical landscapes and adapt mitigation strategies as needed.

Risks to Maintaining Financial Strength

Credit

The Company's credit risk exposure is a function of its electricity sales, trading and hedging activities, and treasury activities including investing and commercial transactions with various suppliers of goods and services. OPG's credit risk exposure relating to energy market transactions as at September 30, 2025 was $619 million, including $532 million with the IESO. OPG continues to consider overall credit risk exposure relating to electricity sales to be low, as the majority of sales are through the IESO-administered market in Ontario.

Commodity Markets

Changes in the market prices of fuels used to produce electricity can adversely impact OPG's earnings and cash flow provided by operating activities. To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts. The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of electricity generation and supply mix and, as such, are subject to change as these forecasts are updated.

	2025 [1]	2026	2027
Estimated fuel requirements hedged *(%)* [2]	100	79	86

[1] Based on actual fuel requirements hedged for the nine months ended September 30, 2025 and forecast for the remainder of the year.

[2] Represents the approximate portion of megawatt-hour (MWh) of expected electricity generation (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric, thermal and combined cycle) for which the price of fuel is fixed, or for which the Company has entered into contractual arrangements to secure the price of fuel or secure the recovery of fuel costs. In the case of regulated and contracted hydroelectric electricity generation in Ontario, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear, thermal and combined cycle) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Electricity Markets

OPG's revenue can be impacted by external factors related to electricity markets. In October 2024, the IESO approved market rules and design required to operationalize the Market Renewal Program (MRP), an IESO initiative to redesign the Ontario's electricity markets. The renewed electricity markets were launched on May 1, 2025. OPG has redesigned and updated its internal systems and processes to effectively participate in the new market. The MRP is not expected to have a material impact on OPG's net income. OPG will continue to assess the post-implementation impacts of the renewed market.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One Limited (Hydro One), the IESO and the OEFC. Transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions were as follows:

	Three Months Ended September 30			
	2025		2024	
(millions of dollars)	**Income**	**Expense**	**Income**	**Expense**
Hydro One				
Electricity sales	**3**	**-**	4	-
Services	**-**	**2**	-	3
Dividends	**1**	**-**	1	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**567**	-	457
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**737**	-	573
Hydroelectric gross revenue charge	**-**	**28**	-	28
OEFC				
Hydroelectric gross revenue charge	**-**	**61**	-	61
Interest expense on long-term notes	**-**	**22**	-	21
Income taxes	**-**	**80**	-	112
Property taxes	**-**	**3**	-	4
IESO				
Electricity-related revenue	**1,959**	**-**	1,785	-
Fair Hydro Trust				
Interest income	**9**	**-**	9	-
	1,972	**1,500**	1,799	1,259

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of any excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at September 30, 2025 and December 31, 2024, the Nuclear Segregated Funds were reported net of amounts due to the Province of $11,991 million and $10,236 million, respectively.

	Nine Months Ended September 30			
	2025		2024	
(millions of dollars)	**Income**	**Expense**	**Income**	**Expense**
Hydro One				
Electricity sales	**18**	**-**	14	-
Services	**-**	**10**	-	7
Dividends	**3**	**-**	3	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**760**	-	905
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**995**	-	1,170
Hydroelectric gross revenue charge	**-**	**91**	-	89
OEFC				
Hydroelectric gross revenue charge	**-**	**156**	-	160
Interest expense on long-term notes	**-**	**65**	-	66
Income taxes	**-**	**421**	-	275
Property taxes	**-**	**10**	-	10
IESO				
Electricity-related revenue	**5,895**	**-**	4,816	-
Fair Hydro Trust				
Interest income	**25**	**-**	25	-
	5,941	**2,508**	4,858	2,682

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of any excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at September 30, 2025 and December 31, 2024, the Nuclear Segregated Funds were reported net of amounts due to the Province of $11,991 million and $10,236 million, respectively.

Balances between OPG and its related parties are summarized below:

(millions of dollars)	**September 30 2025**	**December 31 2024**
Receivables from related parties		
Hydro One	**-**	3
IESO – Electricity related receivables	**532**	608
Fair Hydro Trust	**12**	4
OEFC	**6**	-
Province of Ontario	**4**	1
Loan receivable		
Fair Hydro Trust	**900**	902
Equity securities		
Hydro One shares	**154**	159
Accounts payable, accrued charges and other payables		
Hydro One	**1**	3
OEFC	**64**	85
Province of Ontario	**4**	10
Long-term debt (including current portion)		
Notes payable to OEFC	**2,100**	2,100

OPG may hold Province of Ontario bonds and treasury bills in the Nuclear Segregated Funds and the OPG registered pension plan. As at September 30, 2025, the Nuclear Segregated Funds held $1,762 million of Province of Ontario bonds (December 31, 2024 – $1,740 million) and $10 million of Province of Ontario treasury bills (December 31, 2024 – $8 million). As of September 30, 2025, the OPG registered pension plan held $315 million of Province of Ontario bonds (December 31, 2024 − $327 million) and $10 million of Province of Ontario treasury bills (December 31, 2024 – $9 million). These Province of Ontario bonds and treasury bills are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

INTERNAL CONTROL OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for Internal Control over Financial Reporting (ICFR) and for its Disclosure Controls and Procedures (DC&P). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact on the financial statements.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected financial information for each of the eight most recently completed quarters. This information is derived from OPG's unaudited interim consolidated financial statements and the audited annual consolidated financial statements, and has been prepared in accordance with US GAAP.

(millions of dollars – except where noted) *(unaudited)*	**September 30 2025**	**June 30 2025**	**March 31 2025**	**December 31 2024**
Electricity generation (*TWh*)	**22.3**	21.9	23.5	20.4
Revenue	**2,066**	2,032	2,157	1,838
Net income	**486**	547	509	232
Less: Net income attributable to non-controlling interest	**4**	6	4	4
Net income attributable to the Shareholder	**482**	541	505	228
Earnings per share, attributable to the Shareholder *(dollars)*	**$1.76**	$1.97	$1.84	$0.83

(millions of dollars – except where noted) *(unaudited)*	**September 30 2024**	**June 30 2024**	**March 31 2024**	**December 31 2023**
Electricity generation (*TWh*)	21.7	18.9	21.1	20.8
Revenue	1,891	1,691	1,767	1,894
Net income	383	166	225	454
Less: Net income attribute to the non-controlling interest	4	6	4	4
Net income attributable to the Shareholder	379	160	221	450
Earnings per share, attributable to the Shareholder *(dollars)*	$1.38	$0.58	$0.80	$1.64

[1] Earnings per share was calculated using the weighted average number of shares outstanding of 274.6 million for all periods presented. There were no dilutive securities during any of the periods presented.

KEY OPERATING PERFORMANCE INDICATORS AND NON-GAAP FINANCIAL MEASURES

Key Operating Performance Measures

OPG evaluates the performance of its generating stations using a number of key indicators. Key operating performance indicators aligned with corporate business imperatives include measures of production reliability, cost effectiveness, environmental performance and safety performance. Certain of the measures used vary depending on the generating technology.

Nuclear Unit Capability Factor

The Nuclear Unit Capability Factor is a key measure of nuclear station performance. It measures the amount of energy that the unit(s) generated over a period of time, adjusted for externally imposed constraints such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation. Capability factors are primarily affected by planned and unplanned outages. An outage day represents a single unit being offline or derated for an amount of time equivalent to one day. By industry definition, capability factors exclude production losses beyond plant management's control, such as grid-related unavailability. The nuclear Unit Capability Factor also excludes unit(s) during the period in which they are undergoing refurbishment.

Hydroelectric Availability

Hydroelectric Availability represents the percentage of time the generating unit is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period, weighted by unit capacity.

Thermal Equivalent Forced Outage Rate

Equivalent forced outage rate is an index of the reliability of a generating unit at OPG's wholly-owned thermal stations. It is measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

Thermal Availability

Thermal Availability represents the percentage of time a generating unit at Atura Power's combined cycle plants is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period, averaged by the number of facilities owned and operated through Atura Power. The measure is calculated on a three-year rolling average basis.

Other Key Indicators

In addition to production reliability, cost effectiveness and financial performance indicators, OPG has also identified certain environmental and safety performance measures, which, as applicable, are discussed in the section, *Environmental, Social, Governance and Sustainability*.

Non-GAAP Financial Performance Measures

In addition to net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in this MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide, as applicable, additional information about OPG's performance, facilitate comparison of results over different periods and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance and ensure availability of cost-effective funding. These non-GAAP financial measures are not presented as an alternative to net income or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) Earnings before interest, income taxes, depreciation and amortization is defined as net income before net interest expense, income tax expense and depreciation and amortization expenses.

(2) Gross margin is defined as revenue less fuel expense.

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ONTARIO POWER GENERATION INC.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

SEPTEMBER 30, 2025

ONTARIO POWER GENERATION

INTERIM CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(millions of dollars – except where noted)	Three Months Ended September 30		Nine Months Ended September 30	
	2025	**2024**	**2025**	**2024**
Revenue	**2,066**	1,891	**6,255**	5,349
Fuel expense	**369**	267	**1,025**	760
Gross margin	**1,697**	1,624	**5,230**	4,589
Operations, maintenance and administration expenses	**661**	775	**2,032**	2,485
Depreciation and amortization expenses	**360**	331	**1,070**	935
Accretion on fixed asset removal and nuclear waste management liabilities	**310**	303	**934**	914
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(284)**	(277)	**(848)**	(822)
Property taxes	**12**	12	**37**	36
	1,059	1,144	**3,225**	3,548
Income before other gains, interest and income taxes	**638**	480	**2,005**	1,041
Other gains	**(2)**	(23)	**(27)**	(5)
Income before interest and income taxes	**640**	503	**2,032**	1,046
Net interest expense *(Note 4)*	**40**	48	**148**	144
Income before income taxes	**600**	455	**1,884**	902
Income tax expense	**114**	72	**342**	128
Net income	**486**	383	**1,542**	774
Net income attributable to the Shareholder	**482**	379	**1,528**	760
Net income attributable to non-controlling interest	**4**	4	**14**	14
Basic and diluted earnings per share *(dollars)* [1]	**1.76**	1.38	**5.56**	2.77

[1] The weighted average number of shares outstanding as at September 30, 2025 and 2024 was 274.6 million. There were no dilutive securities during the three and nine month periods ended September 30, 2025 and 2024.

See accompanying notes to the interim consolidated financial statements.

INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

(millions of dollars)	Three Months Ended September 30 2025	2024	Nine Months Ended September 30 2025	2024
Net income	**486**	383	**1,542**	774
Other comprehensive income (loss), net of income taxes *(Note 7)*				
Reclassification to income of amounts related to pension and other post-employment benefits [1]	**-**	(1)	**(1)**	(2)
Reclassification to income of amounts related to derivatives designated as cash flow hedges [2]	**(1)**	(2)	**(1)**	(4)
Net gain (loss) on derivatives designated as cash flow hedges [3]	**1**	7	**(3)**	8
Currency translation adjustment	**43**	(28)	**(69)**	41
Other comprehensive income (loss) for the period	**43**	(24)	**(74)**	43
Comprehensive income	**529**	359	**1,468**	817
Comprehensive income attributable to the Shareholder	**525**	355	**1,454**	803
Comprehensive income attributable to non-controlling interest	**4**	4	**14**	14

[1] Net of income tax recovery of nil for each of the three and nine month periods ended September 30, 2025. Net of income tax expense of nil for each of the three and nine month periods ended September 30, 2024.
[2] Net of income tax recovery of nil for each of the three and nine month periods ended September 30, 2025. Net of income tax recovery of nil and $1 million for the three and nine month periods ended September 30, 2024, respectively.
[3] Net of income tax recovery of nil and $1 million for the three and nine month periods ended September 30, 2025, respectively. Net of income tax expense of $2 million for each of the three and nine month periods ended September 30, 2024.

See accompanying notes to the interim consolidated financial statements.

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(millions of dollars)	Nine Months Ended September 30 2025	2024
Operating activities		
Net income	**1,542**	774
Adjust for non-cash items:		
Depreciation and amortization expenses	**1,070**	935
Accretion on fixed asset removal and nuclear waste management liabilities	**934**	914
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(848)**	(822)
Pension and other post-employment benefit costs *(Note 8)*	**233**	273
Deferred income tax (recovery) expense	**(35)**	6
Regulatory assets and regulatory liabilities	**31**	4
Other gains	**(20)**	(1)
Other	**-**	(17)
Expenditures on fixed asset removal and nuclear waste management	**(689)**	(352)
Reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management	**550**	182
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	**(222)**	(222)
Net changes to other long-term assets and long-term liabilities	**75**	103
Net changes in non-cash working capital balances *(Note 13)*	**469**	5
Cash flow provided by operating activities	**3,090**	1,782
Investing activities		
Investment in property, plant and equipment and intangible assets *(Note 12)*	**(3,940)**	(2,545)
Acquisition of Lightstar Renewables and Lightstar Operations One	**-**	(131)
Proceeds from sale of interest in joint venture	**11**	-
Cash flow used in investing activities	**(3,929)**	(2,676)
Financing activities		
Issuance of long-term debt *(Note 4)*	**1,168**	1,800
Repayment of long-term debt *(Note 4)*	**(621)**	(601)
Issuance of short-term debt *(Note 5)*	**3,301**	2,360
Repayment of short-term debt *(Note 5)*	**(2,310)**	(2,195)
Equity investment from non-controlling interest	**7**	3
Distribution to non-controlling interest	**(13)**	(15)
Cash flow provided by financing activities	**1,532**	1,352
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**(4)**	5
Net increase in cash, cash equivalents and restricted cash	**689**	463
Cash, cash equivalents and restricted cash, beginning of period	**1,363**	1,481
Cash, cash equivalents and restricted cash, end of period	**2,052**	1,944

See accompanying notes to the interim consolidated financial statements.

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	September 30 2025	December 31 2024
Assets		
Current assets		
Cash, cash equivalents and restricted cash	**2,052**	1,363
Equity securities	**154**	159
Receivables from related parties	**554**	616
Nuclear fixed asset removal and nuclear waste management funds	**175**	283
Fuel inventory	**332**	297
Materials and supplies	**200**	145
Regulatory assets *(Note 3)*	**540**	540
Prepaid expenses	**252**	292
Other current assets	**241**	388
	4,500	4,083
Property, plant and equipment	**55,337**	51,290
Less: accumulated depreciation	**15,928**	15,159
	39,409	36,131
Intangible assets	**1,091**	1,029
Less: accumulated amortization	**507**	439
	584	590
Goodwill	**222**	230
Other assets		
Nuclear fixed asset removal and nuclear waste management funds	**22,519**	22,129
Loan receivable from related party	**900**	902
Long-term materials and supplies	**319**	355
Regulatory assets *(Note 3)*	**4,278**	4,367
Investments subject to significant influence	**43**	52
Pension assets	**68**	-
Other long-term assets	**170**	137
	28,297	27,942
	73,012	68,976

See accompanying notes to the interim consolidated financial statements.

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	September 30 2025	December 31 2024
Liabilities		
Current liabilities		
Accounts payable, accrued charges and other payables	**2,440**	2,068
Short-term debt *(Note 5)*	**1,206**	215
Long-term debt due within one year *(Note 4)*	**598**	604
Regulatory liabilities *(Note 3)*	**246**	246
	4,490	3,133
Long-term debt *(Note 4)*	**11,638**	11,103
Other liabilities		
Fixed asset removal and nuclear waste management liabilities *(Note 6)*	**26,524**	26,042
Pension liabilities	**-**	46
Other post-employment benefit liabilities	**2,794**	2,716
Long-term accounts payable and accrued charges	**369**	382
Deferred revenue	**348**	355
Deferred income taxes	**2,527**	2,461
Regulatory liabilities *(Note 3)*	**1,035**	939
	33,597	32,941
Equity		
Common shares [1]	**5,126**	5,126
Class A shares [2]	**787**	787
Contributed surplus	**26**	28
Retained earnings	**16,997**	15,469
Accumulated other comprehensive income *(Note 7)*	**119**	193
Equity attributable to the Shareholder	**23,055**	21,603
Equity attributable to non-controlling interest	**232**	196
Total equity	**23,287**	21,799
	73,012	68,976

[1] 256,300,010 Common shares outstanding at a stated value of $5,126 million as at September 30, 2025 and December 31, 2024.

[2] 18,343,815 Class A shares outstanding at a stated value of $787 million as at September 30, 2025 and December 31, 2024.

Commitments and Contingencies *(Notes 4, 5, 8 and 11)*

See accompanying notes to the interim consolidated financial statements.

INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY (UNAUDITED)

(millions of dollars)	Nine Months Ended September 30 2025	2024
Common shares	**5,126**	5,126
Class A shares	**787**	787
Contributed surplus		
Balance at beginning of period	**28**	30
Reclassification to income of amounts related to gain on deconsolidation of Fair Hydro Trust	**(2)**	(1)
Balance at end of period	**26**	29
Retained earnings		
Balance at beginning of period	**15,469**	14,481
Net income attributable to the Shareholder	**1,528**	760
Balance at end of period	**16,997**	15,241
Accumulated other comprehensive income, net of income taxes *(Note 7)*		
Balance at beginning of period	**193**	(15)
Other comprehensive (loss) income	**(74)**	43
Balance at end of period	**119**	28
Equity attributable to the Shareholder	**23,055**	21,211
Equity attributable to non-controlling interest		
Balance at beginning of period	**196**	182
Income attributable to non-controlling interest	**14**	14
Equity investment from non-controlling interest	**35**	14
Distribution to non-controlling interest	**(13)**	(15)
Balance at end of period	**232**	195
Total equity	**23,287**	21,406

See accompanying notes to the interim consolidated financial statements.

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. BASIS OF PRESENTATION

These interim consolidated financial statements for the three and nine month periods ended September 30, 2025 and 2024 include the accounts of Ontario Power Generation Inc. and its subsidiaries (OPG or the Company). The Company consolidates its interest in entities over which it is able to exercise control and attributes the results to its sole shareholder, the Province of Ontario (the Province or the Shareholder). These interim consolidated financial statements have been prepared and presented in accordance with United States generally accepted accounting principles (US GAAP). These interim consolidated financial statements do not contain all of the disclosures required by US GAAP for annual financial statements. Accordingly, they should be read in conjunction with the annual consolidated financial statements of the Company as at and for the year ended December 31, 2024.

All dollar amounts are presented in Canadian dollars, unless otherwise noted. Certain 2024 comparative amounts have been reclassified from consolidated financial statements previously presented to conform to the 2025 interim consolidated financial statement presentation.

Seasonal Variations

OPG's quarterly electricity generation from the Regulated – Hydroelectric Generation, Contracted Hydroelectric and Other Generation, and Atura Power business segments is affected by changes in grid-supplied electricity demand. Changes in grid-supplied electricity demand are primarily caused by variations in seasonal weather conditions, changes in economic conditions, the impact of small-scale generation embedded in distribution networks, and the impact of conservation efforts. Historically, there has been greater electricity demand in Ontario during the winter and summer months due to heating and air conditioning demands. The financial impact of forgone hydroelectric electricity generation from the Regulated – Hydroelectric Generation business segment due to surplus baseload generation conditions is mitigated by a regulatory deferral and variance account (regulatory account) authorized by the Ontario Energy Board (OEB).

OPG's quarterly electricity generation from hydroelectric facilities is impacted by weather conditions that affect water flows. Historically, there have been higher water flows in the second quarter as a result of snow and ice melt entering the river systems. The financial impact of variability in water flows on the Regulated – Hydroelectric Generation business segment is mitigated by a regulatory account authorized by the OEB.

The financial impact of variability in electricity generation from the Contracted Hydroelectric and Other Generation business segment and the Atura Power business segment is mitigated by the terms of the applicable Energy Supply Agreements with the Independent Electricity System Operator (IESO) for the contracted generating facilities in Ontario.

2. SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

The accounting policies followed in the presentation of these interim consolidated financial statements are consistent with those of the previous fiscal year.

Recent Accounting Pronouncements Not Yet Adopted

Improvements to Income Tax Disclosures

In December 2023, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2023-09, *Improvements to Income Tax Disclosures* (ASU 2023-09), an update to Topic 740, *Income Taxes*. The purpose of ASU 2023-09 is to enhance the transparency and decision usefulness of income tax disclosures through increasing disclosure requirements related to the rate reconciliation and income taxes paid information. The update requires specific categories to be disclosed in the rate reconciliation and additional information for reconciling items that meet a quantitative threshold. The update also requires that entities disclose income taxes paid disaggregated by federal, provincial and foreign taxes and by individual jurisdiction in which income tax paid exceeds five percent of total income taxes paid. The update is effective for annual periods beginning after December 15, 2024. The adoption of the standard update is not expected to have a material impact on the disclosures contained in the Company's annual consolidated financial statements.

Disaggregation of Income Statement Expenses

In November 2024, the FASB issued ASU 2024-03*, Disaggregation of Income Statement Expenses*, an update to Subtopic 220-40, *Income Statement – Reporting Comprehensive Income – Expense Disaggregation Disclosures*. The purpose of the standard update is to improve the disclosures about a public business entity's expenses by requiring more detailed information about the types of expenses (including purchases of inventory and employee compensation) included within consolidated income statement expense captions. The update is effective for fiscal years beginning after December 15, 2026 and interim periods beginning after December 15, 2027, with early adoption permitted. The standard update is to be applied prospectively with the option for retrospective application. The Company is currently evaluating the impact of adoption of the standard update on the disclosures contained within the Company's annual and interim consolidated financial statements.

Determining the Accounting Acquirer in the Acquisition of a Variable Interest Entity

In May 2025, the FASB issued ASU 2025-03, *Determining the Accounting Acquirer in the Acquisition of a Variable Interest Entity*, an update to Topic 805, *Business Combinations* and Topic 810, *Consolidation*. The update amends the guidance for determining the accounting acquirer for a transaction effected primarily by exchanging equity interests in which the legal acquiree is a variable interest entity that meets the definition of a business. The update is effective for fiscal years beginning after December 15, 2026, including interim periods within those fiscal years, with early adoption permitted. The standard update is to be applied prospectively. OPG is currently evaluating the impact of adoption of the standard update to its annual and interim consolidated financial statements.

Targeted Improvements to the Accounting for Internal-Use Software

In September 2025, the FASB issued ASU 2025-06, *Targeted Improvements to the Accounting for Internal-Use Software*, an update to Subtopic 350-40, *Intangibles – Goodwill and Other – Internal-Use Software*. The update amends the guidance by removing all references to software development project stages such that the guidance is neutral to different software development methods. The amendments also apply to website development costs in accordance with Subtopic 350-50, *Intangibles – Goodwill and Other – Website Development Costs*. The update is effective for fiscal years beginning after December 15, 2027, including interim periods within those fiscal years, with early adoption permitted. OPG is currently evaluating the impact of adoption of the standard update to its annual and interim consolidated financial statements.

3. REGULATORY ASSETS AND REGULATORY LIABILITIES

The regulatory assets and regulatory liabilities consist of the following:

As at *(millions of dollars)*	September 30 2025	December 31 2024
Regulatory assets		
Deferral and variance accounts authorized by OEB or Ontario Regulation 53/05		
Rate Smoothing Deferral Account	**696**	677
Nuclear Liability Deferral Account	**465**	520
Capacity Refurbishment Variance Account	**434**	460
Hydroelectric Surplus Baseload Generation Variance Account	**244**	307
Pickering B Variance Account	**235**	131
Pension & OPEB Cash Versus Accrual Differential Deferral Account	**215**	376
Nuclear Development Variance Account	**59**	85
Other deferral and variance accounts [1]	**170**	174
	2,518	2,730
Deferred Income Taxes	**2,300**	2,151
Other	**-**	26
Total regulatory assets	**4,818**	4,907
Less: current portion	**540**	540
Non-current regulatory assets	**4,278**	4,367
Regulatory liabilities		
Deferral and variance accounts authorized by OEB or Ontario Regulation 53/05		
Pension and OPEB Cost Variance Account	**424**	411
Pension & OPEB Cash Payment Variance Account	**244**	321
Hydroelectric Water Conditions Variance Account	**176**	173
Bruce Lease Net Revenues Variance Account	**144**	60
Nuclear Deferral and Variance Over/Under Recovery Variance Account	**90**	61
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges Variance Account	**65**	51
Other deferral and variance accounts [2]	**136**	92
	1,279	1,169
Pension and OPEB Regulatory Liability *(Note 8)*	**2**	16
Total regulatory liabilities	**1,281**	1,185
Less: current portion	**246**	246
Non-current regulatory liabilities	**1,035**	939

[1] Represents amounts for the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, Clarington Corporate Campus Deferral Account, Fitness for Duty Deferral Account, Pickering Closure Costs Deferral Account, Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account, Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account and Impact Resulting from Changes to Pickering Station End-of-Life Dates Deferral Account (December 31, 2017).

[2] Represents amounts for the Income and Other Taxes Variance Account, SR&ED ITC Variance Account, Ancillary Services Net Revenue Variance Account and Sale of Unprescribed Kipling Site Deferral Account.

Effective July 1, 2025, the Province amended *Ontario Regulation 53/05* to clarify the scope of the Pickering B Variance Account (formerly the Pickering B Extension Variance Account) such that OPG can record costs incurred on or after January 1, 2024 to preserve the ability to operate Units 5 to 8 of the Pickering nuclear generating station upon refurbishment for future recovery, subject to review by the OEB. These costs can be recorded in the account until the effective date of the OEB's first order setting nuclear base regulated prices that comes into effect on or after January 1, 2027.

4. LONG-TERM DEBT AND NET INTEREST EXPENSE

Long-term debt consists of the following:

As at *(millions of dollars)*	September 30 2025	December 31 2024
Medium Term Note Program senior notes	**6,550**	5,950
Senior notes payable under corporate credit facilities	**2,811**	2,859
Lower Mattagami Energy Limited Partnership senior notes	**1,995**	1,995
PSS Generating Station Limited Partnership senior notes	**245**	245
UMH Energy Partnership senior notes	**159**	160
OPG Eagle Creek Holdings LLC and subsidiaries senior notes	**499**	516
Other	**25**	25
	12,284	11,750
Less: net fair value premium	**(1)**	-
Less: unamortized bond issuance fees	**(47)**	(43)
Less: amounts due within one year	**(598)**	(604)
Long-term debt	**11,638**	11,103

On March 13, 2025, OPG issued $1 billion of green bonds under its Sustainable Finance Framework, through its Medium Term Note Program. The issuance consisted of $500 million of senior notes maturing in March 2035, with a coupon interest rate of 4.32 percent and $500 million of senior notes maturing in March 2055, with a coupon interest rate of 4.87 percent. The net proceeds from the issuance were used to finance or re-finance Eligible Green Projects as defined under the Sustainable Finance Framework.

OPG repaid long-term debt of $400 million under the Company's Medium Term Note Program during the nine months ended September 30, 2025.

On October 30, 2025, OPG repaid US Dollars (USD) $140 million of senior notes payable by OPG Eagle Creek Holdings LLC and its subsidiaries.

For the nine months ended September 30, 2025, net repayment of long-term debt under the Company's corporate credit facilities totalled $48 million (nine months ended September 30, 2024 – $93 million), which comprised repayments of $220 million (nine months ended September 30, 2024 – $400 million) and issuances of $172 million (nine months ended September 30, 2024 – $307 million).

Net Interest Expense

The following table summarizes the net interest expense:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	2025	2024	2025	2024
Interest on long-term debt	**119**	108	**346**	294
Interest on short-term debt	**(6)**	5	**8**	17
Interest income	**(21)**	(27)	**(63)**	(66)
Interest capitalized to property, plant and equipment and intangible assets	**(47)**	(37)	**(123)**	(98)
Interest related to regulatory assets and regulatory liabilities [1]	**(5)**	(1)	**(20)**	(3)
Net interest expense	**40**	48	**148**	144

[1] Includes interest to recognize the cost of financing regulatory account balances as authorized by the OEB, and interest costs deferred in certain regulatory accounts.

5. SHORT-TERM DEBT

Committed credit facilities and maturity dates as at September 30, 2025 were as follows:

(millions of dollars)		Amount	Maturity
Bank facilities:			
Corporate		**1,000**	May 2030 [1]
Corporate	US Dollars	**750**	May 2026 [2]
Lower Mattagami Energy Limited Partnership		**460**	June 2030 [3]
OPG Eagle Creek Holdings LLC and subsidiaries	US Dollars	**20**	October 2028
Ontario Financing Authority facility		**1,250**	December 2029 [1]
Ontario Electricity Financial Corporation facility		**750**	December 2026 [1]

[1] Represents amounts available under the facility net of debt issuances.
[2] The facility has a one-year extension option beyond the maturity date of May 2026.
[3] A letter of credit of $65 million was outstanding under this facility as at September 30, 2025.

Short-term debt consists of the following:

As at *(millions of dollars)*	**September 30 2025**	**December 31 2024**
Lower Mattagami Energy Limited Partnership	**170**	215
Corporate commercial paper	**1,036**	-
Total short-term debt	**1,206**	215

As at September 30, 2025, a total of $740 million of letters of credit had been issued (December 31, 2024 – $504 million). As at September 30, 2025, this included $314 million for the supplementary pension plans, $267 million for general corporate purposes, $65 million for Lower Mattagami Energy Limited Partnership, $44 million for Atura Power, $20 million for OPG Eagle Creek Holdings LLC and its subsidiaries, $14 million for UMH Energy Partnership, $10 million for Laurentis Energy Partners and its subsidiaries, $5 million for PowerON Energy Solutions LP and $1 million for PSS Generating Station Limited Partnership.

The weighted average interest rate on the short-term debt as at September 30, 2025 is 2.79 percent (December 31, 2024 – 3.71 percent).

6. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

Liabilities for fixed asset removal and nuclear waste management on a present value basis consist of the following:

As at *(millions of dollars)*	**September 30 2025**	**December 31 2024**
Liability for used nuclear fuel management	**16,408**	15,991
Liability for nuclear decommissioning and nuclear low and intermediate level waste management	**9,848**	9,782
Liability for non-nuclear fixed asset removal	**268**	269
Fixed asset removal and nuclear waste management liabilities	**26,524**	26,042

7. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in the balance of each component of accumulated other comprehensive income (loss) (AOCI), net of income taxes, were as follows:

	Nine Months Ended September 30, 2025			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges**	**Pension and OPEB**	**Currency Translation Adjustment**	**Total**
Balance, beginning of period	**5**	**6**	**182**	**193**
Net loss on cash flow hedges	**(3)**	**-**	**-**	**(3)**
Amounts reclassified from AOCI	**(1)**	**(1)**	**-**	**(2)**
Translation of foreign operations	**-**	**-**	**(69)**	**(69)**
Other comprehensive loss for the period	**(4)**	**(1)**	**(69)**	**(74)**
Balance, end of period	**1**	**5**	**113**	**119**

	Nine Months Ended September 30, 2024			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges**	**Pension and OPEB**	**Currency Translation Adjustment**	**Total**
Balance, beginning of period	9	(33)	9	(15)
Net gain on cash flow hedges	8	-	-	8
Amounts reclassified from AOCI	(4)	(2)	-	(6)
Translation of foreign operations	-	-	41	41
Other comprehensive income (loss) for the period	4	(2)	41	43
Balance, end of period	13	(35)	50	28

The significant amounts reclassified out of each component of AOCI, net of income taxes, were as follows:

	Amount Reclassified from AOCI		
(millions of dollars)	**Three Months Ended September 30, 2025**	**Nine Months Ended September 30, 2025**	**Statement of Income Line Item**
Amortization of amounts related to cash flow hedges			
Gains	**(1)**	**(1)**	Revenue and Net interest expense
Income tax recovery	**-**	**-**	Income tax expense
	(1)	**(1)**	
Amortization of amounts related to pension and OPEB			
Net actuarial gains, net of past service costs	**-**	**(1)**	See (1) below
Income tax recovery	**-**	**-**	Income tax expense
	-	**(1)**	
Total reclassifications for the period	**(1)**	**(2)**	

(millions of dollars)	Amount Reclassified from AOCI Three Months Ended September 30, 2024	Amount Reclassified from AOCI Nine Months Ended September 30, 2024	Statement of Income Line Item
Amortization of amounts related to cash flow hedges			
Gains	(2)	(5)	Revenue and Net interest expense
Income tax recovery	-	1	Income tax expense
	(2)	(4)	
Amortization of amounts related to pension and OPEB			
Net actuarial gains, net of past service costs	(1)	(2)	See (1) below
Income tax recovery	-	-	Income tax expense
	(1)	(2)	
Total reclassifications for the period	(3)	(6)	

[1] These AOCI components are included in the computation of pension and OPEB costs (see Note 8 for additional details).

Existing pre-tax net losses for derivatives of nil deferred in AOCI as at September 30, 2025 are expected to be reclassified to net income within the next 12 months.

8. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

OPG's pension and other post-employment benefit (OPEB) costs for the three months ended September 30, 2025 and 2024 were as follows:

(millions of dollars)	Registered Pension Plans 2025	Registered Pension Plans 2024	Supplementary Pension Plans 2025	Supplementary Pension Plans 2024	Other Post-Employment Benefits 2025	Other Post-Employment Benefits 2024
Components of cost recognized for the period						
Current service costs	**75**	76	**2**	2	**26**	24
Interest on projected benefit obligation	**192**	197	**4**	5	**32**	33
Expected return on plan assets, net of expenses	**(269)**	(257)	**-**	-	**-**	-
Amortization of past service (credits) costs [1]	**-**	(1)	**-**	-	**1**	1
Amortization of net actuarial loss (gain) [1]	**-**	-	**1**	1	**(7)**	(7)
Costs recognized [2]	**(2)**	15	**7**	8	**52**	51

[1] The net impact of amortization of past service (credits) costs and net actuarial (gain) loss is recognized as a (decrease) increase to other comprehensive income. This decrease for the three months ended September 30, 2025 was partially offset by a decrease in the Pension and OPEB Regulatory Liability of $5 million (three months ended September 30, 2024 – an increase in the Pension and OPEB Regulatory Asset of $6 million).

[2] These pension and OPEB costs for the three months ended September 30, 2025 exclude the net addition of costs of $21 million resulting from the recognition of changes in the regulatory assets or liabilities for the Pension & OPEB Cost Variance Account, the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account (nine months ended September 30, 2024 – net addition of costs of $17 million).

OPG's pension and OPEB costs for the nine months ended September 30, 2025 and 2024 were as follows:

(millions of dollars)	Registered Pension Plans 2025	Registered Pension Plans 2024	Supplementary Pension Plans 2025	Supplementary Pension Plans 2024	Other Post-Employment Benefits 2025	Other Post-Employment Benefits 2024
Components of cost recognized for the period						
Current service costs	**223**	229	**7**	6	**78**	74
Interest on projected benefit obligation	**575**	593	**13**	13	**96**	98
Expected return on plan assets, net of expenses	**(806)**	(773)	**-**	-	**-**	-
Amortization of past service (credits) costs [1]	**-**	(1)	**-**	-	**3**	2
Amortization of net actuarial loss (gain) [1]	**-**	-	**3**	3	**(21)**	(22)
Costs recognized [2]	**(8)**	48	**23**	22	**156**	152

[1] The net impact of amortization of past service (credits) costs and net actuarial (gain) loss is recognized as a (decrease) increase to other comprehensive income. This decrease for the nine months ended September 30, 2025 was partially offset by a decrease in the Pension and OPEB Regulatory Liability of $14 million (nine months ended September 30, 2024 – an increase in the Pension and OPEB Regulatory Asset of $17 million).

[2] These pension and OPEB costs for the nine months ended September 30, 2025 exclude the net addition of costs of $62 million resulting from the recognition of changes in the regulatory assets or liabilities for the Pension & OPEB Cost Variance Account, the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account (nine months ended September 30, 2024 – net addition of costs of $51 million).

9. RISK MANAGEMENT AND DERIVATIVES

OPG is exposed to risks related to changes in market interest rates on debt, movements in foreign currency that affect the Company's assets, liabilities and forecasted transactions, and fluctuations in commodity prices. Select derivative instruments are used to manage such risks. Derivatives are used as hedging instruments, as well as for trading purposes.

Interest Rates

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in interest rates. Interest rate risk for OPG arises with the need to refinance existing debt or undertake new financing. The management of these risks includes using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

Foreign Exchange

OPG's financial results are exposed to volatility in the Canadian/United States (US) foreign exchange rate as certain materials, services and fuels purchased for generating stations and major development projects, as well as debt issuances, may be denominated in, or tied to, USD. To manage this risk, the Company employs various financial instruments such as forwards and other derivative contracts, in accordance with approved corporate risk management policies. Additionally, volatility in the Canadian/US foreign exchange rate also impacts OPG's financial results from certain of its subsidiaries, whose operations are based exclusively in the US.

Commodity Prices

OPG is exposed to fluctuations in commodity prices. Changes in the market prices of nuclear fuels, oil, gas and biomass used to produce electricity can adversely impact OPG's earnings and cash flow provided by operating activities. To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts.

A number of OPG's hydroelectric facilities in the US sell into the wholesale electricity market, and therefore are subject to volatility of wholesale electricity market pricing. Revenue from these facilities represents a small portion of OPG's overall revenue. The Company may enter into derivative instruments from time to time to further mitigate this risk.

Credit

The Company's credit risk exposure is primarily a function of its electricity and other sales. The majority of OPG's revenue is derived from electricity sales through the IESO administered market. Market participants in the IESO market provide collateral in accordance with the IESO prudential support requirements to cover funds that they might owe to the market. Although the credit exposure to the IESO represents a significant portion of OPG's accounts receivable, the risk is considered acceptable due to the IESO's primary role in the Ontario electricity market. The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts was $1 million as at September 30, 2025 (December 31, 2024 − less than $1 million).

The fair value of the derivative instruments totalled a net liability of $10 million as at September 30, 2025 (December 31, 2024 − net liability of $17 million).

10. FAIR VALUE MEASUREMENTS

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial assets and liabilities into three levels, based on the inputs used in measuring the fair value of the financial assets and liabilities. The fair value hierarchy has the following levels:

- Level 1: Valuation of inputs is based on unadjusted quoted market prices observed in active markets for identical assets or liabilities.
- Level 2: Valuation is based on inputs other than quoted prices under Level 1 that are observable for the asset or liability, either directly or indirectly.
- Level 3: Valuation is based on inputs for the asset or liability that are not based on observable market data.

The fair value of financial instruments traded in active markets is based on quoted market prices as at the interim consolidated balance sheet dates. A market is regarded as active if quoted prices are readily and regularly available from an exchange, dealer, broker, industry group, pricing service or regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's-length basis. The quoted market price used for financial assets held by OPG is the current bid price. These instruments are included in Level 1 and consist primarily of equity investments and fund investments.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing as at the interim consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives and fund investments. Various other fund investments are valued at the unit values supplied by the fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and, therefore, do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If all significant inputs required to fair value an instrument are observable, the instrument is included in Level 2.

If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. Specific valuation techniques are used to value these instruments. Significant Level 3 inputs include recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions and other relevant factors.

A summary of OPG's financial instruments and their fair value as at September 30, 2025 and December 31, 2024 was as follows:

	Fair Value		Carrying Value [1]		
(millions of dollars)	**2025**	**2024**	**2025**	**2024**	**Balance Sheet Line Item**
Nuclear Segregated Funds (includes current portion) [2]	**22,694**	22,412	**22,694**	22,412	Nuclear fixed asset removal and nuclear waste management funds
Loan receivable – from Fair Hydro Trust	**837**	828	**900**	902	Loan receivable from related party
Investment in Hydro One Limited Shares	**154**	159	**154**	159	Equity securities
Long-term debt (includes current portion)	**(11,698)**	(11,204)	**(12,236)**	(11,707)	Long-term debt
Other financial instruments	**159**	129	**159**	129	Various

[1] The carrying values of other financial instruments included in cash and cash equivalents, receivables from related parties, other current assets, short-term debt, and accounts payable, accrued charges and other payables approximate their fair values due to the immediate or short-term maturity of these financial instruments.

[2] The Nuclear Segregated Funds are comprised of the Decommissioning Segregated Fund and the Used Fuel Segregated Fund. OPG's fair value of the Nuclear Segregated Funds is set not to exceed an amount equal to the funding liability pursuant to the Ontario Nuclear Funds Agreement when the Nuclear Segregated Funds are in a surplus position.

The fair value of OPG's long-term debt issued under the Medium Term Note Program is based on indicative pricing from the market. The fair value of these debt instruments is based on Level 2 inputs. The fair value of all other long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs.

The following tables present financial assets and financial liabilities measured at fair value in accordance with the fair value hierarchy:

As at	September 30, 2025			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**6,915**	**7,419**	**-**	**14,334**
Investments measured at NAV [1]				**5,267**
				19,601
Due to Province				**(6,686)**
Used Fuel Segregated Fund, net				**12,915**
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**5,293**	**5,673**	**-**	**10,966**
Investments measured at NAV [1]				**4,118**
				15,084
Due to Province				**(5,305)**
Decommissioning Segregated Fund, net				**9,779**
Equity securities	**154**	**-**	**-**	**154**
Other financial assets	**84**	**1**	**101**	**186**
Liabilities				
Other financial liabilities	**(27)**	**-**	**-**	**(27)**

As at	December 31, 2024			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	7,030	6,676	-	13,706
Investments measured at NAV [1]				4,722
				18,428
Due to Province				(5,691)
Used Fuel Segregated Fund, net				12,737
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	5,362	5,156	-	10,518
Investments measured at NAV [1]				3,702
				14,220
Due to Province				(4,545)
Decommissioning Segregated Fund, net				9,675
Equity securities	159	-	-	159
Other financial assets	73	-	97	170
Liabilities				
Other financial liabilities	(41)	-	-	(41)

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the interim consolidated balance sheets.

During the nine months ended September 30, 2025, there were no transfers between Level 1 and Level 2 and into or out of Level 3.

The changes in the net assets measured at fair value that are classified as Level 3 financial instruments for the nine months ended September 30, 2025 were as follows:

(millions of dollars)	**Other financial instruments**
Opening balance, January 1, 2025	**97**
Realized losses included in revenue	**(2)**
Unrealized losses included in revenue	**(4)**
Purchases	**10**
Closing balance, September 30, 2025	**101**

Investments Measured at Net Asset Value

Nuclear Segregated Funds

Nuclear Segregated Funds' investments classified as Level 3 consist of real estate, infrastructure, other real assets and private debt investments. The fair value of these investments is determined using financial information as provided by the general partners of the limited partnership funds in which the Nuclear Segregated Funds are invested. Direct investments are valued using appropriate valuation techniques, such as recent arm's-length market transactions, references to current fair values of other instruments that are substantially the same, discounted cash flow analyses, third-party independent appraisals, valuation multiples, or other valuation methods. Any control, size, liquidity or other discount premiums on the investments are considered in the determination of fair value.

The process of valuing investments for which no published market price exists is based on inherent uncertainties and the resulting values may differ from values that would have been used had a ready market existed for these investments. The values may also differ from the prices at which the investments may be sold.

The classes of investments within the Nuclear Segregated Funds that are reported on the basis of Net Asset Value (NAV) as at September 30, 2025 were as follows:

(millions of dollars except where noted)	**Fair Value**	**Unfunded Commitments**	**Redemption Frequency**	**Redemption Notice**
Real Assets				
Infrastructure	**4,970**	**1,536**	**n/a**	**n/a**
Real Estate	**3,494**	**1,260**	**n/a**	**n/a**
Private Debt	**478**	**666**	**n/a**	**n/a**
Other	**443**	**16**	**n/a**	**n/a**
Pooled Funds				
Fixed Income	**2,433**	**n/a**	**Daily**	**1-5 days**
Equity	**1,144**	**n/a**	**Daily**	**1-5 days**
Total	**12,962**	**3,478**		

The fair value of the pooled funds is classified as Level 2. Infrastructure, real estate, other real assets, private debt and other investments are measured using NAV as a practical expedient for determining their fair value.

11. COMMITMENTS AND CONTINGENCIES

Litigation

Various legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of business activities. Each of these matters are subject to various uncertainties. Some of these matters may be resolved unfavourably. While it is not possible to determine the ultimate outcome of the various pending actions, it is the Company's belief that their resolution is not likely to have a material adverse impact on its interim consolidated financial position.

Guarantees

As at September 30, 2025, the total amount of guarantees provided by OPG was nil (December 31, 2024 – $30 million).

Contractual Obligations

OPG's contractual obligations as at September 30, 2025 were as follows:

(millions of dollars)	**2025** [1]	**2026**	**2027**	**2028**	**2029**	**Thereafter**	**Total**
Fuel supply agreements	31	227	219	158	147	332	1,114
Contributions to the OPG registered pension plan [2]	32	134	136	-	-	-	302
Long-term debt repayment	198	674	530	262	505	10,115	12,284
Interest on long-term debt	118	466	455	436	424	5,882	7,781
Short-term debt repayment	1,210	-	-	-	-	-	1,210
Commitments related to Darlington Refurbishment project [3]	96	-	-	-	-	-	96
Commitments related to Atura Power development projects [3]	408	126	10	9	-	-	553
Commitments related to Pickering Refurbishment project [3]	433	-	-	-	-	-	433
Commitments related to Darlington New Nuclear Project [3]	294	-	-	-	-	-	294
Operating licences	15	61	63	61	62	179	441
Operating lease obligations	12	14	12	4	3	35	80
Accounts payable, accrued charges and other payables	1,882	9	10	9	10	284	2,204
Other	42	88	50	34	20	89	323
Total	4,771	1,799	1,485	973	1,171	16,916	27,115

[1] Represents amounts for the remainder of the year.
[2] Represents the estimated pension contributions consistent with the period covered by the actuarial valuation of the OPG registered pension plan as at January 1, 2025. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2028. Funding requirements after January 1, 2028 are excluded due to significant variability in the assumptions required to project the timing of future cash flows.
[3] Represents estimated currently committed costs to close the projects, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Contractual and commercial commitments as noted exclude certain purchase orders, as they represent purchase authorizations rather than legally binding contracts, and are subject to change without significant penalties.

Collective Bargaining Agreements

The current two-year collective agreement between the Society of United Professionals (Society) and OPG expires on December 31, 2025. Negotiations for the renewal of the collective agreement began in September 2025 and are ongoing. The Society bargaining unit represents over 30 percent of OPG's workforce.

12. BUSINESS SEGMENTS

For a detailed description of each reportable business segment, measure of profit and loss and the Company's Chief Operating Decision Maker, refer to OPG's annual consolidated financial statements as at and for the year ended December 31, 2024.

Segment Income (Loss)	**Regulated**			**Unregulated**				
For the Three Months Ended September 30, 2025 *(millions of dollars)*	**Nuclear Generation**	**Nuclear Sustainability Services**	**Hydroelectric Generation**	**Contracted Hydroelectric Other Generation**	**Atura Power**	**Other**	**Elimination**	**Total**
Revenue	**1,134**	**-**	**377**	**226**	**298**	**2**	**-**	**2,037**
Leasing revenue	**7**	**-**	**-**	**-**	**-**	**1**	**-**	**8**
Other revenue	**-**	**46**	**-**	**(1)**	**-**	**47**	**(71)**	**21**
Total revenue	**1,141**	**46**	**377**	**225**	**298**	**50**	**(71)**	**2,066**
Fuel expense	**92**	**-**	**86**	**33**	**158**	**-**	**-**	**369**
Gross margin	**1,049**	**46**	**291**	**192**	**140**	**50**	**(71)**	**1,697**
Operations, maintenance and administration expenses	**450**	**46**	**109**	**69**	**27**	**31**	**(71)**	**661**
Depreciation and amortization expenses	**197**	**-**	**67**	**41**	**35**	**20**	**-**	**360**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**307**	**-**	**2**	**1**	**-**	**-**	**310**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(284)**	**-**	**-**	**-**	**-**	**-**	**(284)**
Property taxes	**6**	**-**	**1**	**4**	**-**	**1**	**-**	**12**
Other losses (gains)	**4**	**-**	**1**	**(3)**	**1**	**(5)**	**-**	**(2)**
Income (loss) before interest and income taxes	**392**	**(23)**	**113**	**79**	**76**	**3**	**-**	**640**
Net interest expense								**40**
Income before income taxes								**600**
Income tax expense								**114**
Net income								**486**

Segment Income (Loss)	**Regulated**			**Unregulated**				
For the Three Months Ended September 30, 2024 *(millions of dollars)*	**Nuclear Generation**	**Nuclear Sustainability Services**	**Hydroelectric Generation**	**Contracted Hydroelectric and Other Generation**	**Atura Power**	**Other**	**Elimination**	**Total**
Revenue	1,070	-	373	186	235	3	-	1,867
Leasing revenue	7	-	-	-	-	1	-	8
Other revenue	-	54	-	1	-	38	(77)	16
Total revenue	1,077	54	373	187	235	42	(77)	1,891
Fuel expense	72	-	83	14	98	-	-	267
Gross margin	1,005	54	290	173	137	42	(77)	1,624
Operations, maintenance and administration expenses	580	54	102	72	23	21	(77)	775
Depreciation and amortization expenses	176	-	67	41	30	17	-	331
Accretion on fixed asset removal and nuclear waste management liabilities	-	301	-	2	-	-	-	303
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(277)	-	-	-	-	-	(277)
Property taxes	6	-	-	5	-	1	-	12
Other losses (gains)	2	-	1	(1)	-	(25)	-	(23)
Income (loss) before interest and income taxes	241	(24)	120	54	84	28	-	503
Net interest expense								48
Income before income taxes								455
Income tax expense								72
Net income								383

Segment Income (Loss)	**Regulated**			**Unregulated**				
For the Nine Months Ended September 30, 2025 *(millions of dollars)*	**Nuclear Generation**	**Nuclear Sustainability Services**	**Hydroelectric Generation**	**Contracted Hydroelectric and Other Generation**	**Atura Power**	**Other**	**Elimination**	**Total**
Revenue	**3,395**	**-**	**1,216**	**700**	**836**	**15**	**-**	**6,162**
Leasing revenue	**21**	**-**	**-**	**-**	**-**	**4**	**-**	**25**
Other revenue	**(1)**	**117**	**-**	**-**	**-**	**145**	**(193)**	**68**
Total revenue	**3,415**	**117**	**1,216**	**700**	**836**	**164**	**(193)**	**6,255**
Fuel expense	**253**	**-**	**249**	**88**	**435**	**-**	**-**	**1,025**
Gross margin	**3,162**	**117**	**967**	**612**	**401**	**164**	**(193)**	**5,230**
Operations, maintenance and administration expenses	**1,398**	**117**	**319**	**222**	**80**	**89**	**(193)**	**2,032**
Depreciation and amortization expenses	**587**	**-**	**199**	**124**	**100**	**60**	**-**	**1,070**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**925**	**-**	**7**	**2**	**-**	**-**	**934**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(848)**	**-**	**-**	**-**	**-**	**-**	**(848)**
Property taxes	**19**	**-**	**1**	**14**	**1**	**2**	**-**	**37**
Other losses (gains)	**11**	**-**	**9**	**(22)**	**2**	**(27)**	**-**	**(27)**
Income (loss) before interest and income taxes	**1,147**	**(77)**	**439**	**267**	**216**	**40**	**-**	**2,032**
Net interest expense								**148**
Income before income taxes								**1,884**
Income tax expense								**342**
Net income								**1,542**

Segment Income (Loss)	**Regulated**			**Unregulated**				
For the Nine Months Ended September 30, 2024 *(millions of dollars)*	**Nuclear Generation**	**Nuclear Sustainability Services**	**Hydroelectric Generation**	**Contracted Hydroelectric and Other Generation**	**Atura Power**	**Other**	**Elimination**	**Total**
Revenue	2,836	-	1,160	601	642	12	-	5,251
Leasing revenue	21	-	-	-	-	4	-	25
Other revenue	-	134	-	8	-	134	(203)	73
Total revenue	2,857	134	1,160	609	642	150	(203)	5,349
Fuel expense	216	-	241	40	263	-	-	760
Gross margin	2,641	134	919	569	379	150	(203)	4,589
Operations, maintenance and administration expenses	1,877	134	306	223	73	75	(203)	2,485
Depreciation and amortization expenses	494	-	160	134	90	57	-	935
Accretion on fixed asset removal and nuclear waste management liabilities	-	906	-	6	1	1	-	914
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(822)	-	-	-	-	-	(822)
Property taxes	19	-	1	14	1	1	-	36
Other losses (gains)	6	-	6	(5)	-	(12)	-	(5)
Income (loss) before interest and income taxes	245	(84)	446	197	214	28	-	1,046
Net interest expense								144
Income before income taxes								902
Income tax expense								128
Net income								774

Selected Interim Consolidated Balance Sheets information as at September 30, 2025 *(millions of dollars)*	Regulated		Unregulated				
	Nuclear Generation	Nuclear Sustainability Services	Hydroelectric Generation	Contracted Hydroelectric and Other Generation	Atura Power	Other	Total
Segment property, plant and equipment in-service, net	13,976	-	8,214	6,202	2,940	425	31,757
Segment construction in progress	5,474	-	735	159	1,069	215	7,652
Segment property, plant and equipment, net	19,450	-	8,949	6,361	4,009	640	39,409
Segment intangible assets in-service, net	47	-	2	239	90	138	516
Segment development in progress	28	-	-	1	-	39	68
Segment intangible assets, net	75	-	2	240	90	177	584
Segment goodwill	-	-	-	222	-	-	222
Segment fuel inventory	276	-	-	25	31	-	332
Segment materials and supplies inventory							
Current	197	-	-	3	-	-	200
Long-term	316	-	1	2	-	-	319
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	-	22,694	-	-	-	-	22,694
Loan receivable	-	-	-	-	-	900	900
Fixed asset removal and nuclear waste management liabilities	-	(26,256)	-	(160)	(56)	(52)	(26,524)

Selected Consolidated Balance Sheets information as at December 31, 2024 *(millions of dollars)*	**Nuclear Generation**	**Regulated Nuclear Sustainability Services**	**Hydroelectric Generation**	**Unregulated Contracted Hydroelectric and Other Generation**	**Unregulated Atura Power**	**Unregulated Other**	**Total**
Segment property, plant and equipment in-service, net	14,046	-	8,189	6,322	3,033	224	31,814
Segment construction in progress	3,139	-	398	140	426	214	4,317
Segment property, plant and equipment, net	17,185	-	8,587	6,462	3,459	438	36,131
Segment intangible assets in-service, net	48	-	2	244	95	145	534
Segment development in progress	18	-	-	1	-	37	56
Segment intangible assets, net	66	-	2	245	95	182	590
Segment goodwill	-	-	-	230	-	-	230
Segment fuel inventory	231	-	-	39	27	-	297
Segment materials and supplies inventory							
Current	142	-	-	3	-	-	145
Long-term	352	-	-	3	-	-	355
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	-	22,412	-	-	-	-	22,412
Loan receivable	-	-	-	-	-	902	902
Fixed asset removal and nuclear waste management liabilities	-	(25,773)	-	(161)	(54)	(54)	(26,042)

Segment Capital Expenditure	Regulated		Unregulated				
(millions of dollars)	**Nuclear Generation**	**Nuclear Sustainability Services**	**Hydroelectric Generation**	**Contracted Hydroelectric and Other Generation**	**Atura Power**	**Other**	**Total**
Three months ended September 30, 2025							
Investment in property, plant and equipment and intangible assets	**952**	**-**	**212**	**40**	**85**	**73**	**1,362**
Net change in accruals and other non-cash items							**(38)**
Investment in property, plant and equipment and intangible assets – cash flow							**1,324**
Three months ended September 30, 2024							
Investment in property, plant and equipment and intangible assets	632	-	123	64	53	36	908
Net change in accruals and other non-cash items							(25)
Investment in property, plant and equipment and intangible assets – cash flow							883

Segment Capital Expenditure	Regulated		Unregulated				
(millions of dollars)	**Nuclear Generation**	**Nuclear Sustainability Services**	**Hydroelectric Generation**	**Contracted Hydroelectric and Other Generation**	**Atura Power**	**Other**	**Total**
Nine months ended September 30, 2025							
Investment in property, plant and equipment and intangible assets	**2,710**	**-**	**503**	**109**	**642**	**240**	**4,204**
Net change in accruals and other non-cash items							**(264)**
Investment in property, plant and equipment and intangible assets – cash flow							**3,940**
Nine months ended September 30, 2024							
Investment in property, plant and equipment and intangible assets	1,836	-	282	162	253	94	2,627
Net change in accruals and other non-cash items							(82)
Investment in property, plant and equipment and intangible assets – cash flow							2,545

13. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	Nine Months Ended September 30 2025	2024
Receivables from related parties	**62**	39
Fuel inventory	**(31)**	(2)
Materials and supplies	**(51)**	(1)
Prepaid expenses	**(4)**	(25)
Other current assets	**(4)**	(5)
Accounts payable, accrued charges and other payables	**497**	(1)
Net changes in non-cash working capital balances	**469**	5

14. AGREEMENT TO SELL US ELECTRICITY GENERATION OPERATIONS

In October 2025, OPG entered into an agreement to sell OPG Eagle Creek Holdings LLC's (Eagle Creek) electricity generation and development business in the US for a consideration of USD $1.48 billion, inclusive of debt to be assumed by the purchaser and subject to working capital and other adjustments that are to be finalized upon the closing of the transaction. The closing of the transaction is expected to occur in the first quarter of 2026, and is subject to customary closing conditions including regulatory approvals. Eagle Creek's operating results are reported under the Contracted Hydroelectric and Other Generation business segment.

ONTARIO POWER GENERATION | Electrifying life

News
from Ontario Power Generation

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August 12, 2025

OPG Reports 2025 Second Quarter Financial Results

Toronto – Ontario Power Generation Inc. (OPG or Company) today reported its financial and operating results for the second quarter of 2025, with net income attributable to the Shareholder of $541 million, compared to $160 million for the same period last year. Net income attributable to the Shareholder was $1,046 million for the six months ended June 30, 2025, compared to $381 million for the same period in 2024.

Second quarter highlights include:

Darlington Refurbishment Update; Operating Licence Renewal Underway

With lower feeder installation on the last of the four units of the Darlington nuclear generating station (Darlington GS) nearing completion, the Darlington Refurbishment Project is currently tracking to be completed earlier in 2026 than its original schedule and on budget, including COVID-19 pandemic and inflation impacts.

“The Darlington Refurbishment Project’s success to date is a true testament to the planning completed ahead of project execution and the commitment and expertise of OPG staff, skilled trades and project partners,” said OPG President and CEO Nicolle Butcher. “Darlington has long been a clean energy powerhouse for Ontario, and thanks to this refurbishment, completed safely and with quality, will continue to reliably generate electricity for decades to come.”

The Canadian Nuclear Safety Commission (CNSC) held a public hearing in late June 2025 on OPG’s application to renew Darlington GS’s operating licence for an additional 30 years – the projected lifespan of the refurbished station. The CNSC’s decision, expected in the fall of this year, will be an important step as part of enabling the continued safe and reliable operation of the Darlington GS for decades to come.

OPG’s Role Powering Ontario’s Future

In June 2025, the Ontario government released the province’s first-ever integrated energy plan, *Energy for Generations,* a blueprint to power future growth, and drive the most competitive economy in the G7. OPG’s long-term strategy of maintaining existing and adding net new generation to the grid will help meet that growing need for clean, reliable, and cost-effective electricity.

“With electricity demand forecasted to increase by as much as 75 per cent between now and 2050, OPG will continue to play a key role in meeting Ontarians’ energy needs – affordably and reliably,” said Butcher. “By refurbishing and maintaining our existing fleet, advancing construction on the first of four small modular reactors at the Darlington New

Nuclear Project (DNNP) site, and engaging with Rightsholders and stakeholders on potential new generation opportunities on our strategic sites, we are well-positioned to help power Ontario's clean energy future."

New Isotopes at Darlington

OPG's Darlington GS is set to become the single largest source of potentially life-saving isotope production in North America. In May 2025, the CNSC approved an amendment to the Darlington GS operating licence, permitting OPG subsidiary Laurentis Energy Partners to begin producing Lutetium-177 and Yttrium-90 isotopes from Darlington's Unit 2 reactor.

Lutetium-177 and Yttrium-90 are part of a new wave of targeted radionuclide therapies that deliver radiation directly to cancer cells while sparing healthy tissue and offering new hope to patients with hard-to-treat cancers such as liver, neuroendocrine, and prostate.

"Our Darlington nuclear station is not only helping power Ontario's growing clean energy needs; it is also advancing the future of cancer care," said Butcher. "Cancer patients around the world could soon benefit from life-saving treatment based on these two new medical isotopes produced here in Ontario, from OPG's reactors."

Net Income attributable to the Shareholder

Net income attributable to the Shareholder for the three and six month periods ended June 30, 2025 was $541 million and $1,046 million, respectively, representing an increase of $381 million and $665 million compared to the same periods in 2024. The increases for both periods were primarily attributable to higher earnings from the Regulated – Nuclear Generation business segment as a result of higher electricity generation and lower operating, maintenance and administration expenses due to fewer planned cyclical outage activities.

Generating and Operating Performance

Electricity generated was 21.9 terawatt hours (TWh) and 45.4 TWh for the three and six month periods ended June 30, 2025, respectively, compared to 18.9 TWh and 40.0 TWh for the same periods in 2024.

Regulated – Nuclear Generation Segment

Electricity generation from the Regulated – Nuclear Generation business segment increased by 2.5 TWh and 4.4 TWh during the three and six month periods ended June 30, 2025, respectively, compared to the same periods in 2024. The increases in both periods were primarily due to electricity generation from Unit 1 of the Darlington GS following its return to service from refurbishment in November 2024 and fewer planned outage days at the Darlington GS and the Pickering nuclear generating station (Pickering GS), partially offset by reduced electricity generation resulting from the cessation of commercial operation of Unit 1 and Unit 4 of the Pickering GS in the fourth quarter of 2024.

The Darlington GS unit capability factor increased to 98.6 per cent for both the three and six month periods ended June 30, 2025, compared to 61.2 per cent and 64.7 per cent for the same periods in 2024.

The Pickering GS unit capability factor increased to 92.0 per cent and 94.3 per cent for the three and six month periods ended June 30, 2025, respectively, compared to 76.7 per cent and 78.5 per cent for the same periods in 2024.

The increases in the unit capability factors in both periods were due to fewer planned and unplanned outage days at each generating station.

Regulated – Hydroelectric Generation Segment

Electricity generation from the Regulated – Hydroelectric Generation business segment for the three and six month periods ended June 30, 2025 was comparable to the same periods in 2024.

Availability at the regulated hydroelectric stations decreased to 88.9 per cent and 87.3 per cent for the three and six month periods ended June 30, 2025, respectively, compared to 89.3 per cent and 88.5 per cent for the same periods in 2024. The decreases in both periods were primarily due to higher unplanned outages across the regulated hydroelectric fleet.

Contracted Hydroelectric and Other Generation Segment

Electricity generation from the Contracted Hydroelectric and Other Generation business segment increased by 0.5 TWh and 0.3 TWh for the three and six month periods ended June 30, 2025, respectively, compared to the same periods in 2024, primarily due to higher water flows across the contracted hydroelectric facilities in northeastern Ontario during the second quarter of 2025.

Availability of the hydroelectric stations in the business segment decreased to 82.1 per cent and increased to 85.5 per cent for the three and six month periods ended June 30, 2025, respectively, compared to 84.5 per cent and 84.2 per cent for the same periods in 2024. The decrease for the three months ended June 30, 2025 was primarily due to higher unplanned outages at the Lower Mattagami and Lac Seul hydroelectric generating stations. The increase for the six months ended June 30, 2025 was primarily due to fewer planned outages across the contracted hydroelectric fleet.

Atura Power Segment

Electricity generation from the Atura Power business segment increased by 0.6 TWh for the six months ended June 30, 2025, compared to the same period in 2024, primarily due to higher demand for electricity generation from the combined cycle plants. Electricity generation from the Atura Power business segment for the three months ended June 30, 2025 was comparable to the same period in 2024.

Thermal Availability of the generating stations in the business segment as at June 30, 2025 was comparable to June 30, 2024.

Generation Development

The Company is undertaking a number of generation development and other projects to maximize the value of and expand its generating fleet in support of Ontario's electricity system.

Darlington Refurbishment Project

The Darlington Refurbishment Project will extend the operating life of the four-unit Darlington GS by at least 30 years.

The Unit 4 refurbishment is currently in the third major segment, Reassembly, which includes installation and reassembly of reactor components, and continues to progress as planned. The Reassembly segment is targeted for completion in the third quarter of 2025. Unit 4 is the last Darlington GS unit to undergo refurbishment and is expected to be safely returned to service earlier in 2026 than its original schedule, reflecting the benefits and efficiencies from the experience of the completed refurbishments of Unit 2, Unit 3 and Unit 1.

The total project costs, including the impacts of the COVID-19 pandemic and inflation, are on track to meet the $12.8 billion budget.

Darlington New Nuclear Project

Following the CNSC's approval of the licence to construct and the Province of Ontario's (Province) approval to proceed, OPG is advancing the execution phase of the first small modular reactor (SMR) at the DNNP site. OPG expects to complete the construction of the first SMR by the end of the decade and connect it to the electricity grid by the end of 2030. The total budget for the first SMR, including infrastructure that would be common for all four planned SMRs at the site, is $7.7 billion.

In June 2025, a slurry Tunnel Boring Machine arrived in Ontario in support of the construction of the first SMR, marking a significant project milestone.

OPG also continues to advance planning and licensing activities for three additional SMRs at the DNNP site. Pending the Province and regulatory approvals for the construction of these additional SMRs, the DNNP's total generating capacity is expected to reach approximately 1,200 MW.

Further details on OPG's major projects can be found in Management's Discussion and Analysis as at and for the three and six month periods ended June 30, 2025, section, *Core Business and Outlook* under the heading, *Project Excellence*.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(millions of dollars – except where noted)	Three Months Ended June 30		Six Months Ended June 30	
	2025	**2024**	**2025**	**2024**
Revenue	**2,032**	1,691	**4,189**	3,458
Fuel expense	**284**	240	**656**	493
Operations, maintenance and administration expenses	**660**	840	**1,371**	1,710
Depreciation and amortization expenses	**355**	304	**710**	604
Accretion on fixed asset removal and nuclear waste management liabilities	**311**	305	**624**	611
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(280)**	(274)	**(564)**	(545)
Other net expenses	**3**	33	**-**	42
Earnings before interest and income taxes	**699**	243	**1,392**	543
Net interest expense	**52**	51	**108**	96
Income tax expense	**100**	26	**228**	56
Net income	**547**	166	**1,056**	391
Net income attributable to the Shareholder	**541**	160	**1,046**	381
Net income attributable to non-controlling interest [1]	**6**	6	**10**	10
Earnings (loss) before interest and income taxes				
Electricity generating business segments	**719**	290	**1,409**	608
Regulated – Nuclear Sustainability Services	**(28)**	(28)	**(54)**	(60)
Other	**8**	(19)	**37**	(5)
Earnings before interest and income taxes	**699**	243	**1,392**	543
Cash flow provided by operating activities	**875**	540	**1,629**	1,104
Capital expenditures [2]	**1,500**	993	**2,842**	1,719
Electricity generation (TWh)				
Regulated – Nuclear Generation	**9.7**	7.2	**19.6**	15.2
Regulated – Hydroelectric Generation	**8.4**	8.3	**16.9**	16.8
Contracted Hydroelectric and Other Generation [3]	**2.1**	1.6	**3.3**	3.0
Atura Power	**1.7**	1.8	**5.6**	5.0
Total OPG electricity generation	**21.9**	18.9	**45.4**	40.0
Nuclear unit capability factor (per cent) [4]				
Darlington Nuclear GS	**98.6**	61.2	**98.6**	64.7
Pickering Nuclear GS	**92.0**	76.7	**94.3**	78.5
Availability (per cent)				
Regulated – Hydroelectric Generation	**88.9**	89.3	**87.3**	88.5
Contracted Hydroelectric and Other Generation – hydroelectric stations	**82.1**	84.5	**85.5**	84.2
Atura Power [5]	**87.7**	87.9	**87.7**	87.9

[1] Relates to the following: 25 per cent interest of Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in Lower Mattagami Limited Partnership; 33 per cent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in PSS Generating Station Limited Partnership; 15 per cent and 5 per cent interests of corporations wholly owned by Six Nations of Grand River Development Corporation and the Mississaugas of the Credit First Nation, respectively, in Nanticoke Solar LP; and non-controlling interests in certain electricity generating facilities in the United States.

[2] Includes net changes in accruals.

[3] Includes OPG's proportionate share of electricity generation from co-owned and minority shareholdings in electricity generating facilities.

[4] Excludes nuclear unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 1 of the Darlington GS was excluded from the reported planned and unplanned outage days during its refurbishment period of February 15, 2022 to November 27, 2024 and Unit 4 of the Darlington GS has been excluded from the measure since commencing refurbishment on July 19, 2023.

[5] Reflects the thermal availability of combined cycle plants as at the period end date, calculated on a three-year rolling average basis.

About OPG

As Ontario's largest and one of North America's most diverse electricity generators, OPG invests in local economies and employs thousands of people across Ontario. OPG and its family of companies are advancing the development of new low-carbon technologies, refurbishment projects and electrification initiatives to power the growing demands of a clean economy. Learn more about how the company is delivering these initiatives while prioritizing people, partnerships and strong communities at www.opg.com.

Ontario Power Generation Inc.'s unaudited interim consolidated financial statements and Management's Discussion and Analysis as at and for the three and six month periods ended June 30, 2025, can be accessed on OPG's web site (www.opg.com), the Canadian Securities Administrators' web site (www.sedarplus.com), or can be requested from the Company.

For further information, please contact:

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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2025 SECOND QUARTER REPORT

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ONTARIO POWER GENERATION

ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. and its subsidiaries (OPG or Company) as at and for the three and six month periods ended June 30, 2025. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars, unless otherwise noted.

For a complete description of OPG's corporate strategies, risk management, corporate governance, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, Annual Information Form, and MD&A as at and for the year ended December 31, 2024.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG has also received exemptive relief from the Ontario Securities Commission (OSC) that allows OPG to apply US GAAP instead of International Financial Reporting Standards (IFRS). In September 2022, the OSC approved an exemption which allows the Company to continue to apply US GAAP up to January 1, 2027. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2027. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP*, in OPG's 2024 annual MD&A. This MD&A is dated August 12, 2025.

Additional information about OPG, including the Company's Annual Information Form, is available on SEDAR+ at www.sedarplus.com and the Company's website at www.opg.com.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "budget", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could" and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks and uncertainties, including those set out in the section, *Risk Management*, and forecasts discussed in the section, *Core Business and Outlook*. All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station (GS) performance, availability and operating lives, fuel costs, surplus baseload generation (SBG), fixed asset removal and nuclear waste management obligations and costs, availability of facilities for the permanent disposal of used nuclear fuel and other nuclear waste, performance and earnings of segregated nuclear and OPG pension funds, refurbishment of existing facilities, development and construction of new facilities, acquisition transactions and other business expansion opportunities, performance of acquired businesses, divestiture transactions, defined benefit pension and other post-employment benefit (OPEB) obligations and costs, income taxes, proposed new legislation, government policy including tariffs and the trade environment, the ongoing evolution and growth of electricity industries and markets in Ontario, Canada and the United States of America (United States or US), the continued application and renewal of energy supply agreements (ESAs) with the Independent Electricity System Operator (IESO) and other contracts for non-regulated facilities, inflation, interest rates, foreign currency exchange rates, commodity prices, wholesale electricity market prices, environmental and other regulatory requirements, operating licence applications to the Canadian Nuclear Safety Commission (CNSC) and the Federal Energy Regulatory Commission (FERC), health, safety and environmental developments, changes in the Company's workforce, renewal of union collective agreements, business continuity events, the weather, climate change, technological change, geopolitical events, financing requirements and liquidity, funding sources, applications to the Ontario Energy Board (OEB) for regulated prices, the impact of regulatory decisions by the OEB, clean energy investment government programs, forecasts of earnings, cash flow, earnings before interest, income taxes, depreciation and amortization, gross margin, operations, maintenance and administration (OM&A) expenses and project and other expenditures, retention of critical talent, supply chain availability and capacity, and supplier and third party performance. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events or otherwise.

Use of Non-GAAP Financial Measures

The Company uses the following non-GAAP financial performance measures in the MD&A:

- "Earnings before Interest, Income Taxes, Depreciation and Amortization"; and
- "Gross Margin".

For a detailed description of each of the non-GAAP measures used in this MD&A, refer to the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*. The non-GAAP financial performance measures set out in this MD&A are intended to provide additional information to investors and do not have any standardized meaning under US GAAP, and therefore may not be comparable to other issuers, and should not be considered in isolation or as a substitute for measures of performance prepared under US GAAP.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at June 30, 2025, OPG owned and operated two nuclear generating stations, 66 hydroelectric generating stations, two thermal generating stations, one solar facility and four combined-cycle gas turbine (combined cycle) plants in Ontario, Canada. The combined cycle plants are natural gas-fired facilities owned and operated through the Company's wholly-owned subsidiary operating as Atura Power. Through its US-based wholly-owned subsidiary, OPG Eagle Creek Holdings LLC (Eagle Creek), OPG also wholly or jointly owned and operated 85 hydroelectric generating stations and held minority interests in 14 hydroelectric and two solar facilities in the US as at June 30, 2025. In addition, OPG owned two nuclear generating stations in Ontario, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to, and operated by, Bruce Power L.P. (Bruce Power).

Reporting Structure

The composition of OPG's reportable business segments effective as at June 30, 2025 was as follows:

- Regulated – Nuclear Generation;
- Regulated – Nuclear Sustainability Services;
- Regulated – Hydroelectric Generation;
- Contracted Hydroelectric and Other Generation; and
- Atura Power.

Income from the generating stations leased to Bruce Power is included in revenue under the Regulated – Nuclear Generation business segment. The leased stations are not included in the Company's electricity generation and other operating statistics set out in this MD&A.

Trends

OPG's quarterly electricity generation and the financial results of the Regulated – Nuclear Generation business segment are primarily impacted by maintenance outage cycles, unplanned outage activities and timing of refurbishment activities at the nuclear generating stations, which may result in period-over-period variability in OPG's financial results. The maintenance outage cycle at each of OPG's nuclear generating stations determines the number of planned outages in a particular year. Outage cycles are designed to ensure continued safe and reliable long-term operations of the stations and their compliance with the CNSC's regulatory requirements.

The Darlington and Pickering nuclear generating stations have been designed to operate at full power as baseload generating facilities and therefore their electricity production does not vary with changes in grid-supplied electricity demand.

OPG's quarterly electricity generation from the Regulated – Hydroelectric Generation, Contracted Hydroelectric and Other Generation, and Atura Power business segments is affected by changes in grid-supplied electricity demand. Changes in grid-supplied electricity demand are primarily caused by variations in seasonal weather conditions, changes in economic conditions, the impact of small-scale generation embedded in distribution networks, and the impact of conservation efforts. Historically, there has been greater electricity demand in Ontario during the winter and summer months due to heating and air conditioning demands. The financial impact of forgone hydroelectric electricity generation from the Regulated – Hydroelectric Generation business segment due to SBG conditions is mitigated by a regulatory variance account authorized by the OEB.

OPG's quarterly electricity generation from hydroelectric facilities is impacted by weather conditions that affect water flows. Historically, there have been higher water flows in the second quarter as a result of snow and ice melt entering the river systems. The financial impact of variability in water flows on the Regulated – Hydroelectric Generation business segment is mitigated by regulatory variance accounts authorized by the OEB.

The financial impact of variability in electricity generation from the Contracted Hydroelectric and Other Generation business segment and the Atura Power business segment is mitigated by the terms of the applicable ESAs with the IESO for the contracted generating facilities in Ontario.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as at June 30, 2025 and December 31, 2024 was as follows:

	As At	
(MW)	**June 30 2025**	**December 31 2024**
Regulated – Nuclear Generation [1]	**4,698**	4,698
Regulated – Hydroelectric Generation [2]	**6,566**	6,566
Contracted Hydroelectric and Other Generation [2, 3]	**4,080**	4,080
Atura Power	**2,750**	2,715
Total [4]	**18,094**	18,059

[1] The in-service generating capacity as at June 30, 2025 and December 31, 2024 excludes Unit 4 of the Darlington GS. Unit 4 was taken offline for refurbishment in July 2023 and has a generating capacity of 878 MW. As at June 30, 2025 and December 31, 2024, the Darlington GS had three units in service and the Pickering GS had four units in service.

[2] In-service generating capacity is initially based on estimates at the time of asset in-service. The final capacity may differ once required engineering assessments have been completed and verified.

[3] Includes OPG's proportionate share of in-service generating capacity from co-owned and minority shareholdings in electricity generating facilities.

[4] In-service generating capacity represents the portion of installed capacity (the highest level of MW output which a generating unit can maintain indefinitely under reference conditions, without damage to the unit) that has not been removed from service. The Bruce Power leased stations are excluded from electricity generation and operating statistics set out in this MD&A.

The total in-service generating capacity as at June 30, 2025 increased by 35 megawatts (MW) compared to December 31, 2024. The increase was due to the completion of the contractual generating capacity upgrades at the Halton Hills GS in the first quarter of 2025, as previously awarded by the IESO.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results for the three and six month periods ended June 30, 2025, compared to the same periods in 2024. A discussion of OPG's performance by business segment can be found in the section, *Discussion of Operating Results by Business Segment*.

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars – except where noted)	**2025**	**2024**	**2025**	**2024**
Revenue	**2,032**	1,691	**4,189**	3,458
Fuel expense	**284**	240	**656**	493
Operations, maintenance and administration expenses	**660**	840	**1,371**	1,710
Depreciation and amortization expenses	**355**	304	**710**	604
Accretion on fixed asset removal and nuclear waste management liabilities	**311**	305	**624**	611
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(280)**	(274)	**(564)**	(545)
Other net expenses	**3**	33	**-**	42
Earnings before interest and income taxes	**699**	243	**1,392**	543
Net interest expense	**52**	51	**108**	96
Income tax expense	**100**	26	**228**	56
Net income	**547**	166	**1,056**	391
Net income attributable to the Shareholder	**541**	160	**1,046**	381
Net income attributable to non-controlling interest [1]	**6**	6	**10**	10
Electricity generation (TWh) [2]	**21.9**	18.9	**45.4**	40.0
Cash flow provided by operating activities	**875**	540	**1,629**	1,104
Capital expenditures [3]	**1,500**	993	**2,842**	1,719
Earnings (loss) before interest and income taxes by segment				
Regulated – Nuclear Generation	**407**	14	**755**	9
Regulated – Hydroelectric Generation	**157**	159	**326**	326
Contracted Hydroelectric and Other Generation [4]	**107**	65	**188**	143
Atura Power	**48**	52	**140**	130
Total electricity generating business segments	**719**	290	**1,409**	608
Regulated – Nuclear Sustainability Services	**(28)**	(28)	**(54)**	(60)
Other	**8**	(19)	**37**	(5)
Earnings before interest and income taxes	**699**	243	**1,392**	543

[1] Relates to the following: 25 percent interest of Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in Lower Mattagami Limited Partnership; 33 percent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in PSS Generating Station Limited Partnership; 15 percent interest and 5 percent interest of corporations wholly owned by Six Nations of Grand River Development Corporation and the Mississaugas of the Credit First Nation, respectively, in Nanticoke Solar LP; and non-controlling interests in certain electricity generating facilities in the United States.

[2] Includes OPG's proportionate share of electricity generation from co-owned and minority-held facilities.

[3] Includes net changes in accruals.

[4] Includes contracted revenue from hydroelectric generating stations in Ontario operating under ESAs, with expiration dates ranging from 2059 to 2067.

Second Quarter

Net income attributable to the Shareholder was $541 million for the second quarter of 2025, representing an increase of $381 million compared to the same period in 2024.

Earnings before interest and income taxes (EBIT) were $699 million for the second quarter of 2025, representing an increase of $456 million compared to the same period in 2024.

Significant factors that increased EBIT:

- Increase in revenue of $247 million from the Regulated – Nuclear Generation business segment due to higher electricity generation of 2.5 terawatt hours (TWh). The higher electricity generation was primarily driven by the return to service of Unit 1 of the Darlington nuclear generating station (Darlington GS) following refurbishment in November 2024 and fewer planned outage days at both the Darlington GS and the Pickering nuclear generating station (Pickering GS), partially offset by the cessation of commercial operation of Unit 1 and Unit 4 of the Pickering GS in the fourth quarter of 2024; and
- Lower OM&A expenses of $176 million from the Regulated – Nuclear Generation business segment, largely due to lower expenditures related to the cyclical maintenance activities as a result of fewer planned outage days at both the Darlington GS and Pickering GS, and the cessation of commercial operation of Unit 1 and Unit 4 of the Pickering GS in the fourth quarter of 2024.

Net interest expense in the second quarter of 2025 was comparable to the same period in 2024. An increase in the interest expense on the Company's long-term debt due to bond issuances during 2024 and the first quarter of 2025 was largely offset by a higher amount of interest costs capitalized related to increased project expenditures, including the Pickering Refurbishment project and the Darlington New Nuclear Project (DNNP), and a higher amount of interest recorded as recoverable from customers through deferral and variance accounts (regulatory accounts).

Income tax expense increased by $74 million in the second quarter of 2025, compared to the same period in 2024. The increase was primarily due to the impact of higher earnings before income taxes.

Year-To-Date

Net income attributable to the Shareholder was $1,046 million for the first six months of 2025, representing an increase of $665 million compared to the same period in 2024.

Earnings before interest and income taxes were $1,392 million for the first six months of 2025, an increase of $849 million compared to the same period in 2024.

Significant factors that increased EBIT:

- Increase in revenue of $438 million from the Regulated - Nuclear Generation business segment due to higher electricity generation of 4.4 TWh. The higher electricity generation was primarily driven by the return to service of Unit 1 of the Darlington GS following refurbishment in November 2024 and fewer planned outage days at both the Darlington GS and the Pickering GS, partially offset by the cessation of commercial operation of Unit 1 and Unit 4 of the Pickering GS in the fourth quarter of 2024; and
- Lower OM&A expenses of $344 million from the Regulated - Nuclear Generation business segment, largely due to lower expenditures related to the cyclical maintenance activities as a result of fewer planned outage days at both the Darlington GS and Pickering GS, and the cessation of commercial operation of Unit 1 and Unit 4 of the Pickering GS in the fourth quarter of 2024.

Net interest expense increased by $12 million for the six months ended June 30, 2025, compared to the same period in 2024, primarily due to interest expense from bond issuances during 2024 and the first quarter of 2025. This was partially offset by a higher amount of interest costs capitalized related to increased project expenditures, including the Pickering Refurbishment project and the DNNP, and a higher amount of interest recorded as recoverable from customers through regulatory accounts.

Income tax expense increased by $172 million for the six months ended June 30, 2025, compared to the same period in 2024. The increase was primarily due to the impact of higher earnings before income taxes.

Electricity Generation

Electricity generation for the three and six month periods ended June 30, 2025 and 2024 was as follows:

	Three Months Ended June 30		Six Months Ended June 30	
(TWh)	**2025**	**2024**	**2025**	**2024**
Regulated – Nuclear Generation	**9.7**	7.2	**19.6**	15.2
Regulated – Hydroelectric Generation	**8.4**	8.3	**16.9**	16.8
Contracted Hydroelectric and Other Generation [1]	**2.1**	1.6	**3.3**	3.0
Atura Power	**1.7**	1.8	**5.6**	5.0
Total OPG electricity generation	**21.9**	18.9	**45.4**	40.0

[1] Includes OPG's proportionate share of electricity generation from co-owned and minority shareholdings in electricity generating facilities.

Total OPG electricity generation increased by 3.0 TWh and 5.4 TWh for the three and six month periods ended June 30, 2025, respectively, compared to the same periods in 2024. The increases in both periods were primarily due to higher electricity generation from the Regulated – Nuclear Generation business segment.

Electricity generation from the Regulated – Nuclear Generation business segment increased by 2.5 TWh and 4.4 TWh for the three and six month periods ended June 30, 2025, respectively, compared to the same periods in 2024. The increases in both periods were primarily due to electricity generation from Unit 1 of the Darlington GS following its return to service from refurbishment in November 2024 and fewer planned outage days at both the Darlington and Pickering nuclear generating stations. The increases were partially offset by reduced electricity generation resulting from the cessation of commercial operation of Unit 1 and Unit 4 of the Pickering GS in the fourth quarter of 2024.

Electricity generation from the Regulated – Hydroelectric Generation business segment for the three and six month periods ended June 30, 2025 was comparable to the same periods in 2024.

Electricity generation from the Contracted Hydroelectric and Other Generation business segment increased by 0.5 TWh and 0.3 TWh for the three and six month periods ended June 30, 2025, respectively, compared to the same periods in 2024, primarily due to higher water flows across the contracted hydroelectric facilities in northeastern Ontario during the second quarter of 2025.

Electricity generation from the Atura Power business segment increased by 0.6 TWh for the six months ended June 30, 2025, compared to the same period in 2024, primarily due to higher demand for electricity generation from the combined cycle plants. Electricity generation from the Atura Power business segment for the three months ended June 30, 2025 was comparable to the same period in 2024.

Ontario's electricity demand as reported by the IESO for the three and six month periods ended June 30, 2025, excluding electricity exports out of the province, was 33.3 TWh and 71.0 TWh, respectively, compared to 32.7 TWh and 68.5 TWh for the same periods in 2024.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric and certain nuclear generating stations, and other grid-connected renewable resources. Baseload generation surplus in Ontario was higher in the three and six month periods ended June 30, 2025, compared to the same periods in 2024. Production forgone at OPG's regulated hydroelectric stations due to SBG conditions was 0.1 TWh and 0.6 TWh for the three and six month periods ended June 30, 2025, respectively, compared to 0.2 TWh for both periods in 2024. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear generating stations due to SBG conditions.

Cash Flow from Operations

Cash flow provided by operating activities was $875 million and $1,629 million for the three and six month periods ended June 30, 2025, respectively, compared to $540 million and $1,104 million for the same periods in 2024.

The increases for the three and six month periods ended June 30, 2025 were primarily due to higher revenue receipts from the Regulated – Nuclear Generation business segment and lower income tax installment payments.

Capital Expenditures

Capital expenditures for the three and six month periods ended June 30, 2025 and 2024 were as follows:

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2025**	**2024**	**2025**	**2024**
Regulated – Nuclear Generation – Darlington Refurbishment	**178**	262	**407**	493
Regulated – Nuclear Generation – Pickering Refurbishment	**283**	83	**692**	124
Regulated – Nuclear Generation – DNNP	**219**	150	**415**	240
Regulated – Nuclear Generation – Excluding Darlington Refurbishment, Pickering Refurbishment and DNNP	**138**	208	**244**	347
Regulated – Hydroelectric Generation	**167**	86	**291**	159
Contracted Hydroelectric and Other Generation	**35**	45	**69**	98
Atura Power	**390**	126	**557**	200
Other	**90**	33	**167**	58
Total capital expenditures [1]	**1,500**	993	**2,842**	1,719

[1] Includes net changes in accruals.

Total capital expenditures increased by $507 million and $1,123 million for the three and six month periods ended June 30, 2025, respectively, compared to the same periods in 2024.

Capital expenditures for the Darlington Refurbishment project decreased by $84 million and $86 million for the three and six month periods ended June 30, 2025, respectively, compared to the same periods in 2024. The decreases were primarily due to the return to service of Unit 1 of the Darlington GS from refurbishment in November 2024, partially offset by higher expenditures on refurbishment activities at Unit 4 of the Darlington GS.

Capital expenditures for the Pickering Refurbishment project increased by $200 million and $568 million for the three and six month periods ended June 30, 2025, respectively, compared to the same periods in 2024. The increases in both periods were due to higher expenditures on pre-execution refurbishment activities for Units 5 to 8 of the Pickering GS reflecting the project's transition to the definition phase in January 2025.

Capital expenditures for the DNNP increased by $69 million and $175 million for the three and six month periods ended June 30, 2025, respectively, compared to the same periods in 2024. The increases in both periods were driven by commencement of construction activities for the first small modular reactor (SMR), Unit 1, and infrastructure that would be common for all four planned SMRs at the DNNP site in the second quarter of 2025 and higher expenditures for site preparation and other ongoing development activities for the additional three planned SMRs.

Excluding the Darlington Refurbishment project, the Pickering Refurbishment project and the DNNP, capital expenditures for the Regulated – Nuclear Generation business segment decreased by $70 million and $103 million for the three and six month periods ended June 30, 2025, respectively, compared to the same periods in 2024. The decreases in both periods were primarily driven by the completion of the water treatment facility at the Darlington GS in the second quarter of 2024, and the completion of the replacement of primary moisture separators, a component of steam generators, in Unit 1 and Unit 4 of the Darlington GS.

Capital expenditures for the Regulated – Hydroelectric Generation business segment increased by $81 million and $132 million for the three and six month periods ended June 30, 2025, respectively, compared to the same periods in 2024. The increases in both periods were primarily due to higher expenditures on the redevelopments of the Kakabeka Falls and several other hydroelectric generating stations as well as the ongoing refurbishment program across the hydroelectric fleet.

Capital expenditures for the Contracted Hydroelectric and Other Generation business segment decreased by $10 million and $29 million for the three and six month periods ended June 30, 2025, respectively, compared to the same periods in 2024. The decreases in both periods were primarily due to lower expenditures on the Smoky Falls Dam Safety project.

Capital expenditures for the Atura Power business segment increased by $264 million and $357 million for the three and six month periods ended June 30, 2025, respectively, compared to the same periods in 2024. The increases in both periods were primarily due to higher expenditures on the development of a battery energy storage system at the Napanee GS site (Napanee BESS). The increase for the six months ended June 30, 2025 was also attributable to higher expenditures for the expansion of the combined cycle plant at the Napanee GS. Both facilities will operate under long-term agreements with the IESO.

Capital expenditures within the Other category increased by $57 and $109 million for the three and six month periods ended June 30, 2025, respectively, compared to the same periods in 2024. The increases in both periods were primarily due to higher expenditures related to the retrofitting and renovation of OPG's new corporate headquarters building in Oshawa, Ontario prior to the planned occupancy in summer 2025.

Further details on the Company's major projects can be found in sections, *Core Business and Outlook* under the heading, *Project Excellence,* and *Significant Developments* under the heading, *Project Excellence.*

SIGNIFICANT DEVELOPMENTS

Project Excellence

Darlington Refurbishment

The Darlington GS Unit 4 refurbishment activities are in the Reassembly segment, which includes the installation and reassembly of reactor components, and are progressing as planned. The Reassembly segment is targeted for completion in the third quarter of 2025, with lower feeder installation series currently in progress. During the second quarter of 2025, the project completed the Unit 4 fuel channel installation series. In August 2025, the project completed the reconditioning of the Unit 4 turbine generator, which included the overhaul of the turbine generator, installation of the turbine control systems upgrade and static commissioning. Unit 4 is expected to be safely returned to service earlier in 2026 than its original schedule, reflecting the benefits and efficiencies from the experience of the completed refurbishments of Unit 2, Unit 3 and Unit 1.

The total project costs, including the impacts of the COVID-19 pandemic, are on track to meet the $12.8 billion budget.

Darlington New Nuclear Project

OPG continues to advance the DNNP and expects to complete the construction of Canada's first grid-scale SMR by the end of the decade and connect it to the electricity grid by the end of 2030, using the BWRX-300 reactor plant technology.

On April 4, 2025, the CNSC announced its decision to issue a power reactor construction licence to OPG, authorizing the construction of one SMR at the DNNP site. The licence is valid until March 31, 2035 and includes standard licence conditions as well as three Regulatory Hold Points (RHPs) at key project milestones during the licence to construct phase. The removal of the RHPs is tied to completion of design and safety analysis and will allow for the progression of the detailed design and phased construction. Overall, the licence conditions and hold points will enable effective regulatory oversight of the licensed activities.

In May 2025, the Province announced its support for OPG to proceed with the execution phase of the first SMR at the DNNP site. The total cost of the four-unit DNNP, including interest, cost escalation, and contingency, is currently estimated at approximately $20.9 billion. The first unit SMR is expected to cost $6.1 billion along with systems and services that would be common to all four SMRs planned as part of the project of $1.6 billion. The total budget of $7.7 billion represents the release-quality estimate for both the first SMR and shared infrastructure, and was approved by the OPG Board of Directors (Board). OPG and its project partners will continue to refine the total estimated project cost during the definition phase of the remaining three units, incorporating lessons learned from the construction of the first SMR and the Darlington Refurbishment project. Pending the Province and regulatory approvals for the construction of the three additional SMRs, the DNNP's total generating capacity is expected to reach approximately 1,200 MW.

The SMRs at the DNNP site are prescribed for rate regulation by the OEB. As a rate regulated project, the recovery of the costs of the DNNP will be reviewed by the OEB in a future proceeding for OPG's regulated prices. The Province has also indicated that it is exploring potential financial policy tools that would benefit ratepayers. In parallel, OPG continues to explore optimal financing arrangements in support of funding requirements for the planned capital investments.

The Darlington Refurbishment project and Darlington New Nuclear Project are discussed further in the section, *Core Business and Outlook* under the heading, *Project Excellence.*

Ontario's Integrated Energy Plan

On June 12, 2025, the Ontario Ministry of Energy and Mines released its first-ever integrated energy plan, *Energy for Generations*, which provides a roadmap for addressing the province's future energy needs. The plan highlights that Ontario's demand for energy is projected to grow by 75 percent leading up to 2050. During the same month, the Province introduced the *Protect Ontario by Securing Affordable Energy Act, 2025* (Bill 40) to support the implementation of the integrated energy plan.

In alignment with the Province's integrated energy plan, OPG is advancing a portfolio of major nuclear and hydroelectric refurbishment projects to extend the life of its generating assets, building the G7's first SMR, exploring the potential for new generation at its existing sites in southern Ontario, including new nuclear energy generation in Port Hope, and exploring opportunities for additional hydroelectric generation in northern Ontario.

Operational Excellence

Darlington GS World Association of Nuclear Operators Recognition

In the second quarter of 2025, OPG hosted a World Association of Nuclear Operators (WANO) peer review for the Darlington GS, the first since 2020. The review focused on the progress made in safety, equipment reliability, performance and continuous improvement at the station over the past five years. Through this visit, the Darlington GS was recognized as performing at the highest levels of operational safety and reliability.

New Energy Supply Agreement for Lennox GS

In May 2025, OPG secured a new five-year ESA for the Lennox GS, an oil/gas dual-fueled power plant, under the IESO's Medium-Term 2 (MT2) Request for Proposal process. Together with its existing ESA, this will provide revenue certainty for the Lennox GS until 2034, enabling it to continue providing 2,100 MW of electricity generating capacity to the Ontario grid. The existing ESA will remain in place until April 2029, at which time the new ESA will take effect. The results of the Lennox GS are reported in OPG's Contracted Hydroelectric and Other Generation business segment.

CORE BUSINESS AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements* at the beginning of the MD&A.

The following sections provide an update to OPG's disclosures in the 2024 annual MD&A related to its four business imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these imperatives as part of OPG's corporate strategy is included in the 2024 annual MD&A in the sections, *The Company* and *Core Business and Outlook*.

Operational Excellence

Electricity Generation Production and Reliability

Nuclear Operations

OPG's plan to optimize the end of operations dates for the Pickering GS includes operating Units 5 to 8 until the end of September 2026, prior to their planned refurbishment. The current CNSC power reactor operating licence for the Pickering GS is valid until August 31, 2028. On June 27, 2025, OPG submitted an application to the CNSC to renew the power reactor operating licence for the Pickering GS for a period of 10 years, inclusive of planned refurbishment activities. The two-part public hearing on the application is scheduled to be held by the CNSC in April 2026 and June 2026.

In January 2025, the Province announced its approval of OPG's plan to proceed with the project definition phase as the next step toward refurbishing Units 5 to 8 of the Pickering GS. The Board approved budget for this work is $4.1 billion, bringing the total Board-approved budget for the project to date to $6.2 billion. During the definition phase, OPG expects to complete a high-quality cost estimate and schedule for the project, further procurement and contracting work, continue to optimize project scope, and develop the project execution plan. This work is ongoing, with the definition phase expected to last through 2026. Once refurbished, the Pickering GS would continue to provide over 2,000 MW of baseload generating capacity, equivalent to powering approximately two million homes, to help meet Ontario's demand for electricity. The refurbishment of Units 5 to 8 of the Pickering GS is anticipated to be completed by the mid-2030s.

In May 2024, OPG submitted an application to the CNSC to renew the power reactor operating licence for the Darlington GS, valid until November 30, 2025, for a period of 30 years. The two-part public hearing on the application took place in March 2025 and June 2025.

Based on the results of planned inspections of the units of the Darlington GS, OPG identified that the primary moisture separators, a component of steam generators (SG), required replacement on all units to ensure ongoing safe, reliable and efficient operations throughout the station's extended lifespan. The function of the primary moisture separators is to provide high quality dry steam to the downstream turbine equipment. There are four SGs in each Darlington GS unit and each SG has 104 primary moisture separators. In May 2025, the Board approved the scope of the project to replace the primary moisture separators in Unit 2 and those in the remaining two SGs of Unit 3, with an overall budget of $253 million. The project commenced execution planning activities in July 2025. The replacement of all other primary moisture separators at the Darlington GS was completed in 2023 and 2024.

On June 6, 2023, the Federal Court of Canada (Federal Court) endorsed the CNSC's move to require pre-placement and random alcohol and drug testing of workers in safety-critical positions, as mandated by the CNSC's approved regulatory document *REGDOC 2.2.4 – Fitness for Duty, Vol. II: Managing Alcohol and Drug Use* (version 3) (REGDOC 2.2.4) for use at Canadian high-security nuclear sites in November 2020. The requirements outlined in REGDOC 2.2.4 ensure that Canada is in line with the international best practices for the operation of high-security nuclear facilities. On July 11, 2023, the Power Workers' Union (PWU) and the Society of United Professionals (Society) filed a motion to appeal the Federal Court's June 6, 2023 decision, and a motion to stay the implementation of the pre-placement and

random alcohol and drug testing regimes, pending the outcome of the appeal. On October 27, 2023, the stay motion was granted, and all licensees were restricted from implementing such testing pending the final disposition of the appeal, which was heard in January 2024. On November 6, 2024, the Federal Court of Appeal upheld the Federal Court's June 6, 2023 ruling. On May 29, 2025, after the unions sought to appeal the matter before the Supreme Court of Canada, a decision was received dismissing the unions' application for leave, ending the legal review process regarding the validity of pre-placement and random alcohol and drug testing provisions of REGDOC 2.2.4. The CNSC has provided direction to OPG to implement these provisions by no later than January 1, 2026.

Renewable Generation Operations

OPG continues to progress on an ongoing refurbishment program for its hydroelectric generating units across Ontario. In the second quarter of 2025, OPG completed the refurbishment of Unit 9 at the R.H. Saunders GS, located on the St. Lawrence River in eastern Ontario, marking the completion of the first of 16 units at the station scheduled for refurbishment.

Collective Agreements

Construction work in Ontario is performed through craft unions with established bargaining rights at OPG facilities. These bargaining rights are established either through the Electrical Power Systems Construction Association (EPSCA) or directly with OPG or its wholly-owned subsidiaries. The associated collective agreements are negotiated either directly between the parties or through the EPSCA, as applicable. Negotiations for the renewal of all EPSCA collective agreements have been completed, with all agreements finalized. All renewal agreements have five-year terms covering the period from May 1, 2025 to April 30, 2030. EPSCA is a voluntary association of owners and contractors who perform work in Ontario's electrical power systems sector.

Project Excellence

Darlington New Nuclear Project

OPG is advancing the execution phase of the first SMR at the DNNP site. During the second quarter of 2025, OPG continued off-site fabrication of the structural components for the reactor building, progressed the laying of the foundations for the power block buildings, and continued excavation activities for the reactor building shaft and the condenser cooling water launch shaft. In June 2025, a slurry tunnel boring machine arrived in Ontario to support the construction of the first SMR, marking a significant project milestone. This machine will bore and line the condenser cooling water tunnel, an essential component for bringing the first SMR online. At the same time, the condenser cooling water system is being constructed in Lake Ontario offshore of the DNNP site. OPG also continues to advance planning and licensing activities for three additional SMRs at the DNNP site, including site grading activities, which are nearing completion.

OPG's major projects in the execution phase as at June 30, 2025 are outlined below:

Project	Capital Expenditures		Approved Budget	Expected In-service Date	Current Status
(millions of dollars)	Year-to-date	Life-to-date			
Darlington Refurbishment Project	407	11,597	12,800 [1]	Unit 4 – 2026	The Unit 4 refurbishment is currently in the Reassembly segment and progressing as planned. The project is tracking on budget and is expected to be completed earlier in 2026 than its original schedule.
Darlington New Nuclear Project	415	1,386	7,700 [2]	Unit 1 – 2030	The project is advancing the execution phase of the first SMR at the DNNP site. The project is tracking on schedule and on budget.
Redevelopment of Kakabeka Falls Hydroelectric GS	63	102	519	2028	Demolition work is underway, including the powerhouse lean-to structure, penstocks and surge building. The remaining design activities are progressing as planned. The project is tracking on schedule and on budget.
Atura Power Development Projects	464	752	1,500 [3]	Niagara Hydrogen Centre – 2026 Napanee BESS – 2026 Napanee Combined Cycle GS Expansion Project – 2028	The Niagara Hydrogen Centre project continues to progress construction activities, with civil, foundation and structural steel installation completed. Major substation equipment has also been installed. The Napanee BESS project continues to progress civil and foundation construction work, which is nearing completion. The complete battery system has been successfully received, marking a key milestone in the equipment delivery schedule. The installation of the critical equipment, including battery system, transformers and transmission line cabling, is underway. Engineering, design and permitting activities for the Napanee Combined Cycle GS Expansion project continue to progress on schedule. Early site preparation has commenced. These projects are tracking within the total approved budget.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS. The refurbishments of Units 1 to 3 have been completed. Refurbishment of the four generating units is expected to extend the operating life of the station by at least 30 years.

[2] The approved budget of $7.7 billion includes $6.1 million allocated to Unit 1 and $1.6 billion allocated to systems and services that would be common to all four SMRs planned as part of the project.

[3] The total project budget of approximately $1.5 billion is for the Niagara Hydrogen Centre, the Napanee BESS and the Napanee Combined Cycle GS Expansion projects.

Financial Strength

Increasing Revenue, Reducing Costs and Achieving Appropriate Return

In line with its commercial mandate, OPG is focused on increasing revenue and net income, and achieving an appropriate return on the Shareholder's investment, while seeking to minimize the impact on electricity customers through continuous improvement in the Company's cost structure.

For regulated operations, achievement of the above objectives is largely dependent on outcomes of OPG's applications for regulated prices to the OEB and prudent growth of rate base earning a return. Rate base for OPG represents the average net level of investment in regulated fixed and intangible assets in service and an allowance for working capital.

The following table presents the OEB-authorized regulated prices for electricity generated from OPG's regulated facilities in Ontario for the period from January 1, 2024 to December 31, 2026 in effect as of the date of this MD&A:

($/MWh)	**2024**	**2025**	**2026**
Regulated – Nuclear Generation			
Base regulated price [1]	103.48	**102.85**	111.33
Deferral and variance account rate riders [2]	4.28	**8.76**	12.43
Total regulated price	107.76	**111.61**	123.76
Regulated – Hydroelectric Generation			
Base regulated price	43.88	**43.88**	43.88
Deferral and variance account rate riders [2]	3.64	**3.30**	3.30
Total regulated price	47.52	**47.18**	47.18

[1] Base regulated prices for the nuclear facilities were established using a rate smoothing approach that defers a portion of each year's approved nuclear revenue requirement for future collection in the Rate Smoothing Deferral Account. Base regulated prices for the nuclear facilities do not include amounts deferred in the Rate Smoothing Deferral Account.

[2] Deferral and variance account riders reflect the OEB's January 2022 payment amounts order that authorized recovery and repayment of balances recorded in regulatory accounts as at December 31, 2019, and, effective July 2024, the OEB's June 2024 decision and order that authorized recovery and repayment of balances recorded in regulatory accounts as at December 31, 2022.

The base regulated prices for OPG's nuclear electricity generation in effect for the period from January 1, 2022 to December 31, 2026 were established by the payment amounts order issued by the OEB in January 2022 reflecting the OEB's decisions on OPG's 2022-2026 rate application issued during the second half of 2021.

Pursuant to *Ontario Regulation 53/05*, the base regulated price for OPG's hydroelectric electricity generation (hydroelectric base regulated price) for the period from January 1, 2022 to December 31, 2026 has been set equal to the 2021 hydroelectric base regulated price.

In 2024, the OEB initiated a generic cost of capital proceeding to review the methodology for determining the cost of capital parameters and deemed capital structure used for setting utility rates. As part of its decision issued in March 2025, the OEB updated the cost of capital parameters including the prescribed rate of return on deemed equity applicable to all electricity transmitters, electricity distributors, natural gas utilities, and rate-regulated electricity generators. As a result, the interim prescribed return on a deemed equity portion (ROE) of 9.25 percent applicable to 2025 cost-based rate applications was updated to 9.0 percent on a final basis, effective January 1, 2025. The prescribed ROE will continue to be updated annually through the OEB's ROE adjustment formula. These changes do not affect the prescribed ROE levels or other cost of capital parameters reflected in OPG's previously authorized regulated prices for the period through December 31, 2026. While the OEB did not make changes to deemed capital structures in this proceeding, it stated that it would consider, on its merits, a proposal by OPG to modify its deemed capital structure, should OPG submit one in its next application for new regulated prices. For information on OEB-approved cost of capital

parameters and rate base levels reflected in OPG's authorized regulated prices through December 31, 2026, refer to OPG's 2024 annual MD&A in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation.*

Effective July 1, 2025, the Province amended *Ontario Regulation 53/05* to clarify the scope of the Pickering B Extension Variance Account such that OPG can record costs incurred on or after January 1, 2024 to preserve the ability to operate Units 5 to 8 of the Pickering GS upon refurbishment for future recovery, subject to review by the OEB.

In April 2025, the Province released a proposal for potential amendments to *Ontario Regulation 53/05* to allow for the creation of a new variance account to record pre-development expenses for proposed hydroelectric projects by OPG for future recovery, subject to review by the OEB. The comment period for the proposal ended on June 13, 2025.

Under the current OEB rate-setting framework, OPG begins recovering costs through regulated prices once projects are placed in-service. In May 2025, the Province proposed potential changes in regulations that would establish a new mechanism for concurrent cost recovery to allow OPG to recover debt interest during the construction periods of the DNNP and the Pickering Refurbishment project (if the project is approved to proceed). The proposed change would also prescribe a new OEB-regulated generator and establish the applicable rate-setting framework to enable OPG to enter into commercial partnerships for the DNNP. The comment period for the proposal ended on June 26, 2025.

For generation assets that do not form part of the rate regulated operations, OPG generally seeks to secure long-term revenue arrangements that support an appropriate return on the investment. In line with this strategy, all of OPG's non-regulated facilities in Ontario are subject to ESAs with the IESO. These contracts are generally designed to provide for recovery of operating costs and capital investment in the underlying facilities and a return on invested capital, subject to the facilities continuing to meet their contractual obligations.

Ensuring Availability of Cost Effective Funding

OPG actively monitors its funding requirements and forecasts availability of funds to ensure that it can meet the Company's operational needs, project and other commitments, and long-term obligations. In addition to funds generated from operations, OPG currently utilizes the following primary funding sources: commercial paper; letters of credit; credit facilities; public debt offerings; debt sourced from the Ontario Electricity Financial Corporation (OEFC) and Ontario Financing Authority (OFA), agencies of the Province; and private placement and other project financing arrangements.

Credit Ratings

Maintaining an investment grade credit rating supports OPG's ability to access cost effective financing. As at June 30, 2025, the Company's credit ratings were as follows:

Type of Rating	DBRS Limited (DBRS) [1]	S&P Global Ratings (S&P) [2]	Moody's Investors Service (Moody's) [3]
Issuer rating	A (low)	BBB+	A3
Senior unsecured debt	A (low)	BBB+	A3
Trend/Outlook	Stable	Stable	Stable
Commercial paper program – Canada	R-1 (low)	A-1 (low)	NR [4]
Commercial paper program – US	NR [4]	A-2	P-2

[1] In April 2025, DBRS confirmed OPG's A (low) issuer rating, A (low) senior unsecured debt rating and R-1 (low) Canadian commercial paper rating, all with Stable trends.
[2] In August 2024, S&P confirmed OPG's ratings including BBB+ issuer rating with stable outlook, BBB+ senior unsecured debt rating and A-1 (low) Canada commercial paper rating.
[3] In May 2025, Moody's confirmed OPG's A3 issuer rating with stable outlook, A3 senior unsecured debt rating and P-2 US commercial paper rating.
[4] NR indicates no rating assigned.

Additional discussion of the Company's credit facilities and liquidity can be found in the section, *Liquidity and Capital Resources*.

Growth and Transformation

OPG strives to be a leader in the North American energy transition, while maintaining and expanding the Company's scale and industry leadership through the pursuit of commercial-based opportunities. This strategy considers the Company's financial position, anticipated future changes in the generating fleet, and the evolving external environment in which it operates. The strategy is also informed by industry, technological, environmental, social, and economic factors. Opportunities are evaluated on an ongoing basis using financial and risk-based analyses as well as strategic considerations, including the evaluation of partnership opportunities with other entities where aligned with OPG's business objectives.

Nuclear Services Collaboration

In July 2025, OPG signed a letter of intent (LOI) with Orlen Synthos Green Energy, a Polish-based energy company, to support the deployment of BWRX-300 SMRs in Poland. Through this LOI, OPG will have the opportunity to offer a range of pre-operational services, including site assessments, project management and strategic advisory support, and to explore future opportunities for operational services for the Polish SMRs.

Medical Isotopes

On May 26, 2025, the CNSC announced its decision to amend OPG's power reactor operating licence for the Darlington GS to authorize production of lutetium-177 (Lu-177) and yttrium-90 (Y-90) isotopes using the existing target delivery system at Unit 2 of the Darlington GS. Laurentis Energy Partners (LEP), a wholly-owned subsidiary of OPG, will produce Lu-177 and Y-90, which are used to deliver targeted radionuclide therapy for treating certain cancers and tumors. Lu-177 is used to treat rare tumors and prostate cancer, while Y-90 is primarily used for the treatment of liver cancer and other large inoperable tumors.

Social Licence

OPG is committed to maintaining high standards of public health and safety and corporate citizenship, including environmental stewardship, transparency, community engagement and Indigenous relations. The Company also strives to be a leader in climate change action, equity, diversity and inclusion (ED&I) practices, and advancing reconciliation with Indigenous peoples.

Further details on social licence activities and initiatives can be found in the section, *Environmental, Social, Governance and Sustainability*.

Outlook

As at June 30, 2025, OPG's capital expenditures for the year 2025 were forecasted at approximately $6 billion, approximately $1 billion higher than previously disclosed in the 2024 annual MD&A. The increase is mainly due to the timing associated with pre-execution phase activities for the planned refurbishment of Units 5 to 8 of the Pickering GS and work advanced across the Atura Power development projects.

OPG's net income outlook for 2025, which is expected to be higher than net income for 2024, remains consistent with the outlook provided in the 2024 annual MD&A.

The Company's operating results in 2025 may be impacted by macro-economic factors and geopolitical events, including tariffs and the trade environment, as discussed further in the section, *Risk Management.*

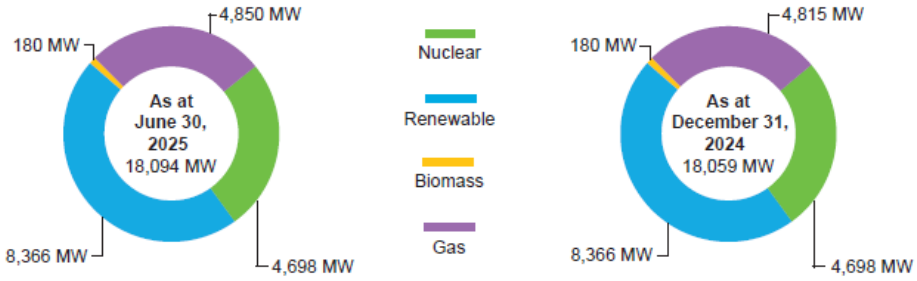
Further details on OPG's outlook, including capital expenditures and financing and liquidity, can be found in OPG's 2024 annual MD&A in the section, *Core Business and Outlook* under the heading, *Outlook*.

ENVIRONMENTAL, SOCIAL, GOVERNANCE AND SUSTAINABILITY

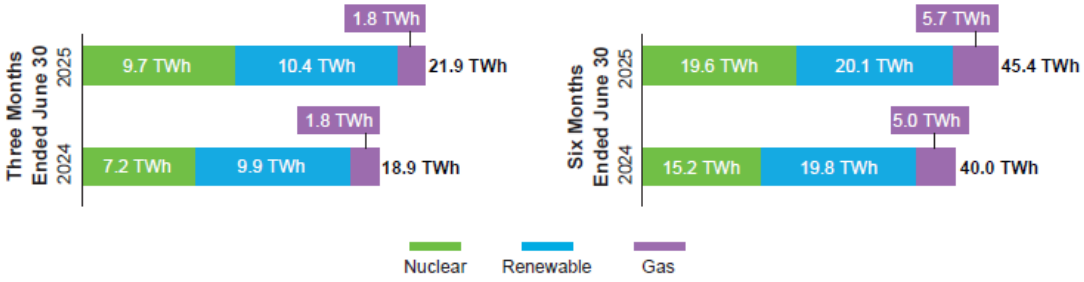
The following sections provide an update to disclosures in the 2024 annual MD&A, related to OPG's social licence activities, sustainability, and environmental, social, governance (ESG) metrics.

Climate-Related Performance and Key Metrics

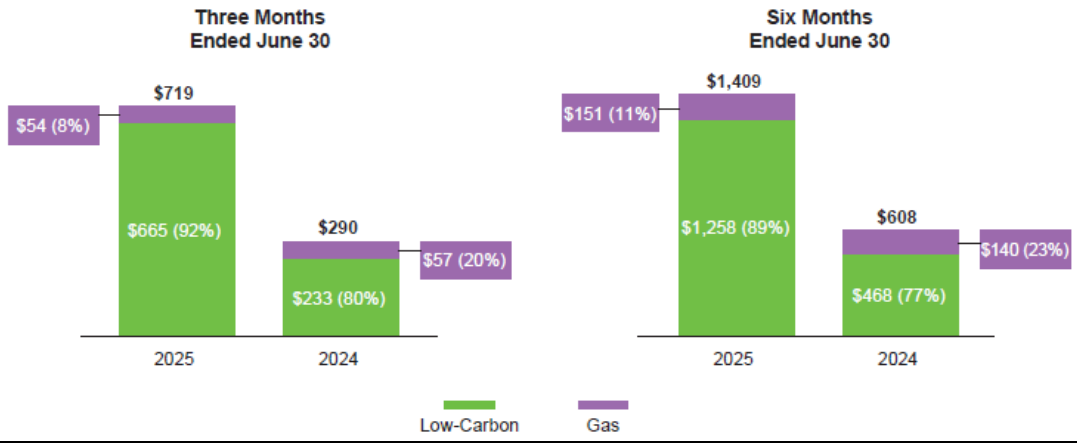
In-service generating capacity by generation type (MW) [1]



Electricity generation by generation type (TWh) [1, 2]



EBIT from generating stations by facility category (millions of dollars); Climate-related transition risk [1]



[1] Includes OPG's proportionate share of in-service generating capacity and electricity generation from co-owned and minority-held facilities. Nuclear generating units undergoing refurbishment are excluded. Gas category includes the dual-fueled Lennox GS and the Company's combined cycle plants operated through Atura Power.

[2] Electricity generated from the Biomass category for the three and six month periods ended June 30, 2025 represents 0.03 TWh and 0.06 TWh, respectively (three and six month periods ended June 30, 2024 – nil and 0.04 TWh, respectively).

Climate Change Metrics	
In-service generating capacity by generation type [1]	In-service generating capacity from gas generation sources increased as at June 30, 2025, compared to December 31, 2024, due to the completion of the contractual generating capacity upgrades at the Halton Hills GS in the first quarter of 2025. Low-carbon sources continue to account for the majority of OPG's total in-service generating capacity.
Electricity generation by generation type [1]	Low-carbon sources, which comprise nuclear, renewable and biomass generation, accounted for approximately 92 percent and 88 percent of OPG's total electricity generation during the three and six month periods ended June 30, 2025, respectively, compared to 90 percent and 88 percent during the same periods in 2024. The percentage increase for the three months ended June 30, 2025 was primarily due to the increase in electricity generation from the Regulated – Nuclear Generation business segment. For further details, refer to the section, *Highlights* under the heading, *Electricity Generation*.
EBIT from generating stations by facility category; Climate-related transition risk	The portion of EBIT from low-carbon electricity generation increased during the three and six month periods ended June 30, 2025, compared to the same periods in 2024, primarily due to higher electricity generation and lower OM&A expenses from the Regulated – Nuclear Generation business segment. For further details, refer to the section, *Discussion of Operating Results by Business Segment* under the heading, *Regulated – Nuclear Generation Segment*.

[1] Identifies capacity available from OPG's different electricity generation sources and tracks low-carbon energy capacity relative to other sources. Nuclear, Renewable (which includes hydroelectric and solar) and Biomass (which uses wood pellets from sustainably managed forests) generation are considered to be low-carbon emitting generation sources.

Equity, Diversity and Inclusion

With the support of its employees, host communities and business partners, the Company continues to advance its ED&I Strategy and priorities to build a workforce that represents our communities and create a culture of inclusion. In May 2025, OPG updated its ED&I Strategy actions, building on the prior commitments as discussed in the 2024 annual MD&A in the section *Environmental, Social, Governance, and Sustainability* under the heading *Equity, Diversity and Inclusion*. OPG's ED&I Strategy can be found on the Company's website www.opg.com.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars – except where noted)	**2025**	**2024**	**2025**	**2024**
Electricity Generation (TWh)	**9.7**	7.2	**19.6**	15.2
Revenue	**1,135**	880	**2,274**	1,780
Fuel expense	**79**	79	**161**	144
Gross margin	**1,056**	801	**2,113**	1,636
Operations, maintenance and administration expenses	**443**	619	**948**	1,292
Property taxes	**6**	7	**13**	13
Other losses	**4**	4	**7**	4
Earnings before interest, income taxes, depreciation and amortization	**603**	171	**1,145**	327
Depreciation and amortization expenses	**196**	157	**390**	318
Earnings before interest and income taxes	**407**	14	**755**	9

Earnings before interest and income taxes from the segment increased by $393 million and $746 million for the three and six month periods ended June 30, 2025, respectively, compared to the same periods in 2024.

The increases in segment earnings were largely due to higher revenue of $247 million and $438 million as a result of higher electricity generation of 2.5 TWh and 4.4 TWh, respectively, during the three and six month periods ended June 30, 2025, compared to the same periods in 2024. Additionally, the increases in both periods were also driven by lower OM&A expenses of $176 million and $344 million, respectively, largely due to lower expenditures related to the cyclical maintenance activities as a result of fewer planned outage days at the Darlington GS and Pickering GS, and the cessation of commercial operation of Unit 1 and Unit 4 of the Pickering GS in the fourth quarter of 2024.

The lower depreciation and amortization expenses of $17 million and $37 million for the three and six month periods ended June 30, 2025, respectively, compared to the same periods in 2024, excluding amortization expense related to the recovery and repayment of OEB-authorized regulatory account balances, were primarily due to the cessation of commercial operation of Unit 1 and Unit 4 of the Pickering GS in the fourth quarter of 2024. The decreases were partially offset by lower amounts of depreciation expense recorded as recoverable from customers through regulatory accounts and higher depreciation expense recognized from placing capital in service, including the return to service of Unit 1 of the Darlington GS following refurbishment in November 2024.

The increases in segment earnings for the three and six month periods ended June 30, 2025, compared to the same periods in 2024, were partially offset by a higher amount of $48 million recorded in the second quarter of 2024 as recoverable from customers in the Pickering B Extension Variance Account in connection with forgone electricity generation due to activities associated with the extension of commercial operation of Units 5 to 8 of the Pickering GS to September 2026.

An increase in revenue for the three and six month periods ended June 30, 2025 reflecting the impact of the new rate riders for disposition of regulatory accounts under the OEB's June 2024 decision and order on OPG's application for such disposition, effective July 1, 2024, was largely offset by a corresponding increase in the amortization expense of regulatory assets and regulatory liabilities recorded for regulatory account balances.

The planned and unplanned outage days at the Darlington and Pickering nuclear generating stations were as follows:

	Three Months Ended June 30		Six Months Ended June 30	
	2025	**2024**	**2025**	**2024**
Planned Outage Days				
Darlington GS [1]	**1.7**	58.5	**2.7**	100.9
Pickering GS	**0.4**	96.6	**7.6**	194.5
Unplanned Outage Days				
Darlington GS [1]	**2.9**	12.8	**6.0**	28.8
Pickering GS	**30.6**	39.2	**35.9**	48.8

[1] The planned and unplanned outage days exclude unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 1 of the Darlington GS was excluded from the reported planned and unplanned outage days during its refurbishment period of February 15, 2022 to November 27, 2024 and Unit 4 of the Darlington GS has been excluded from the measure since commencing refurbishment on July 19, 2023.

The lower planned outage days at the Darlington GS for the three and six month periods ended June 30, 2025, compared to the same periods in 2024, were driven by the impact of the station's cyclical maintenance outage on the station's Unit 2 during the first half of 2024.

The lower planned outage days at the Pickering GS for the three and six month periods ended June 30, 2025, compared to the same periods in 2024, were driven by the impact of the station's cyclical maintenance schedule and other planned maintenance and repair work executed at the station during 2024.

The lower unplanned outages days at the Darlington GS for the three and six month periods ended June 30, 2025, compared to the same periods in 2024, were primarily driven by steam generators repair activities on the station's Unit 3 in the first half of 2024.

The lower unplanned outage days at the Pickering GS for the three and six month periods ended June 30, 2025, compared to the same periods in 2024, were primarily due to fueling machine recovery activities executed at the station in the first half of 2024, partially offset by higher unplanned outage days associated with non-routine maintenance work performed in the second quarter of 2025.

The Unit Capability Factors for the Darlington and Pickering nuclear generating stations were as follows:

	Three Months Ended June 30		Six Months Ended June 30	
	2025	**2024**	**2025**	**2024**
Unit Capability Factor *(%)* [1, 2]				
Darlington GS	**98.6**	61.2	**98.6**	64.7
Pickering GS	**92.0**	76.7	**94.3**	78.5

[1] Nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment.
[2] Nuclear Unit Capability Factor is defined in the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*.

The Unit Capability Factor at the Darlington GS and Pickering GS increased for the three and six month periods ended June 30, 2025, compared to the same periods in 2024, due to fewer planned and unplanned outage days at each station, respectively.

Regulated – Nuclear Sustainability Services Segment

(millions of dollars – except where noted)	Three Months Ended June 30		Six Months Ended June 30	
	2025	**2024**	**2025**	**2024**
Revenue	**35**	44	**71**	80
Operations, maintenance and administration expenses	**35**	44	**71**	80
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**308**	302	**618**	605
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(280)**	(274)	**(564)**	(545)
Loss before interest and income taxes	**(28)**	(28)	**(54)**	(60)

The segment loss before interest and income taxes was the same for the three month period ended June 30, 2025 compared to the same period in 2024, and lower by $6 million for the six month period ended June 30, 2025, compared to the same period in 2024. The decrease for the six months ended June 30, 2025 was primarily due to higher earnings on the nuclear fixed asset removal and nuclear waste management segregated funds (Nuclear Segregated Funds), largely offset by higher accretion expense on the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities). The higher accretion expense on the Nuclear Liabilities was due to the increase in the present value of the underlying obligation to reflect the passage of time.

The higher earnings from the Nuclear Segregated Funds were primarily due to the growth in the present value of the underlying funding liabilities per the approved Ontario Nuclear Funds Agreement (ONFA) reference plan in effect. As both the Decommissioning Segregated Fund and the Used Fuel Segregated Fund were in an overfunded position during the six months ended June 30, 2025, and during the same period in 2024, they were not impacted by market returns or the rate of return guarantee provided by the Province for a portion of the Used Fuel Segregated Fund. When both funds are in an overfunded position, OPG limits the amount of Nuclear Segregated Funds assets reported on the consolidated balance sheet to the present value of the underlying funding liabilities per the approved ONFA reference plan in effect.

Further details on the accounting for the Nuclear Segregated Funds can be found in OPG's 2024 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds.*

Regulated – Hydroelectric Generation Segment

(millions of dollars – except where noted)	Three Months Ended June 30		Six Months Ended June 30	
	2025	**2024**	**2025**	**2024**
Electricity generation (TWh)	**8.4**	8.3	**16.9**	16.8
Revenue [1]	**431**	403	**839**	787
Fuel expense	**91**	88	**163**	158
Gross margin	**340**	315	**676**	629
Operations, maintenance and administration expenses	**109**	103	**210**	204
Property taxes	**-**	1	**-**	1
Other losses	**8**	5	**8**	5
Earnings before interest, income taxes, depreciation and amortization	**223**	206	**458**	419
Depreciation and amortization expenses	**66**	47	**132**	93
Earnings before interest and income taxes	**157**	159	**326**	326

[1] During the three and six month periods ended June 30, 2025, the Regulated – Hydroelectric Generation business segment revenue included incentive payments of $7 million and $12 million, respectively, related to the OEB-approved hydroelectric incentive mechanism (three and six month periods ended June 30, 2024 – incentive payments of $7 million and $9 million, respectively). The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

Earnings before interest and income taxes from the segment for the three and six month periods ended June 30, 2025 were comparable to the same periods in 2024.

An increase in revenue for the three and six months ended June 30, 2025 reflecting the impact of the new rate riders for disposition of regulatory accounts under the OEB's June 2024 decision and order on OPG's application for such disposition, effective July 1, 2024, was largely offset by a corresponding increase in the amortization expense of regulatory assets and regulatory liabilities recorded for regulatory account balances.

The Hydroelectric Availability for the generating stations reported in the Regulated – Hydroelectric Generation business segment was as follows:

	Three Months Ended June 30		Six Months Ended June 30	
	2025	**2024**	**2025**	**2024**
Hydroelectric Availability *(%)* [1]	**88.9**	89.3	**87.3**	88.5

[1] Hydroelectric Availability is defined in the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*.

The Hydroelectric Availability decreased for the three and six month periods ended June 30, 2025, compared to the same periods in 2024, primarily due to higher unplanned outages across the regulated hydroelectric fleet.

Contracted Hydroelectric and Other Generation Segment

(millions of dollars – except where noted)	Three Months Ended June 30		Six Months Ended June 30	
	2025	**2024**	**2025**	**2024**
Electricity generation (TWh)	**2.1**	1.6	**3.3**	3.0
Revenue	**245**	212	**475**	422
Fuel expense	**32**	13	**55**	26
Gross margin	**213**	199	**420**	396
Operations, maintenance and administration expenses	**75**	79	**153**	151
Accretion on fixed asset removal liabilities	**3**	2	**5**	4
Property taxes	**5**	4	**10**	9
Other gains	**(19)**	(1)	**(19)**	(4)
Earnings before interest, income taxes, depreciation and amortization	**149**	115	**271**	236
Depreciation and amortization expenses	**42**	50	**83**	93
Earnings before interest and income taxes	**107**	65	**188**	143

Earnings before interest and income taxes from the segment increased by $42 million and $45 million for the three and six month periods ended June 30, 2025, respectively, compared to the same periods in 2024. The increases for both periods were primarily due to higher earnings from US operations, reflecting higher wholesale electricity market prices and lower depreciation and amortization expenses during the second quarter of 2025 as well as a one-time gain of $18 million recognized in the second quarter of 2025 related to a service contract termination settlement. The increase for the six months ended June 30, 2025 was also due to higher earnings from the Ontario-based hydroelectric facilities, driven by higher revenue from the Lower Mattagami generating stations.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) within the Contracted Hydroelectric and Other Generation segment were as follows:

	Three Months Ended June 30		Six Months Ended June 30	
	2025	**2024**	**2025**	**2024**
Hydroelectric Availability *(%)* [1, 2]	**82.1**	84.5	**85.5**	84.2
Thermal EFOR *(%)* [2]	**13.9**	0.9	**17.3**	0.4

[1] Hydroelectric Availability reflects the Company's hydroelectric generating stations in Ontario and the United States.
[2] Hydroelectric Availability and Thermal EFOR are defined in the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*.

The Hydroelectric Availability decreased for the three months ended June 30, 2025, compared to the same period in 2024, primarily due to higher unplanned outages at the Lower Mattagami and Lac Seul hydroelectric generating stations. The Hydroelectric Availability increased for the six months ended June 30, 2025, compared to the same period in 2024, primarily due to fewer planned outages across the contracted hydroelectric fleet.

The Thermal EFOR increased for the three and six month periods ended June 30, 2025, compared to the same periods in 2024, due to higher unplanned outages at the Lennox GS.

Atura Power Segment

(millions of dollars – except where noted)	Three Months Ended June 30		Six Months Ended June 30	
	2025	**2024**	**2025**	**2024**
Electricity generation (TWh)	**1.7**	1.8	**5.6**	5.0
Revenue	**194**	172	**538**	407
Fuel expense	**82**	60	**277**	165
Gross margin	**112**	112	**261**	242
Operations, maintenance and administration expenses	**30**	30	**53**	50
Accretion on fixed asset removal liabilities	**-**	-	**1**	1
Property taxes	**1**	-	**1**	1
Other losses	**1**	-	**1**	-
Earnings before interest, income taxes, depreciation and amortization	**80**	82	**205**	190
Depreciation and amortization expenses	**32**	30	**65**	60
Earnings before interest and income taxes	**48**	52	**140**	130

Earnings before interest and income taxes from the segment increased by $10 million for the six months ended June 30, 2025, compared to the same period in 2024. The increase in earnings was primarily due to a higher gross margin in the first quarter of 2025 as a result of higher demand for electricity generation from the combined cycle plants. Earnings before interest and income taxes from the segment for the three months ended June 30, 2025 were comparable to the same period in 2024.

The Thermal Availability for the assets within the Atura Power business segment was as follows:

	As At June 30	
	2025	**2024**
Thermal Availability *(%)* [1]	**87.7**	87.9

[1] Thermal Availability is defined in the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*. The measure reflects the availability of the combined cycle plants as at the period end date, calculated on a three-year rolling average basis.

The Thermal Availability for the combined cycle plants as at June 30, 2025 was comparable to June 30, 2024.

LIQUIDITY AND CAPITAL RESOURCES

OPG maintains a range of funding sources to ensure sufficient liquidity and meet financing requirements. These sources are used for multiple purposes including: to invest in plants and technologies, undertake major projects and business acquisitions, fund long-term obligations such as contributions to the pension fund, make payments under the OPEB plans, fund expenditures on Nuclear Liabilities not eligible for reimbursement from the Nuclear Segregated Funds, service and repay long-term debt, and provide general working capital. Highlights of OPG's interim consolidated cash flow position are noted below.

Changes in cash and cash equivalents for the three and six month periods ended June 30, 2025 and 2024 were as follows:

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2025**	**2024**	**2025**	**2024**
Cash, cash equivalents and restricted cash, beginning of period	**2,612**	926	**1,363**	1,481
Cash flow provided by operating activities	**875**	540	**1,629**	1,104
Cash flow used in investing activities	**(1,534)**	(1,050)	**(2,605)**	(1,861)
Cash flow (used in) provided by financing activities	**(123)**	1,461	**1,443**	1,149
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**(7)**	2	**(7)**	6
Net (decrease) increase in cash, cash equivalents and restricted cash	**(789)**	953	**460**	398
Cash, and cash equivalents and restricted cash, end of period	**1,823**	1,879	**1,823**	1,879

For a discussion of cash flow provided by operating activities, refer to the details in the section, *Highlights* under the heading, *Overview of Results.*

Investing Activities

Cash flow used in investing activities for the three and six month periods ended June 30, 2025 increased by $484 million and $744 million, respectively, compared to the same periods in 2024. The increases for both periods were primarily due to the higher capital expenditures within the Regulated – Nuclear Generation and Atura Power business segments. The increase for the six months ended June 30, 2025 was partially offset by the acquisition of Lightstar Renewables LLC and Lightstar Operations One LLC on January 31, 2024.

Financing Activities

Cash flow provided by financing activities for the three months ended June 30, 2025 decreased by $1,584 million, compared to the same period in 2024. The decrease was primarily due the issuance of $1 billion green bonds through the Company's Medium Term Note Program and higher net issuances of corporate commercial paper during the second quarter of 2024, partially offset by higher repayment of long-term debt the second quarter of 2025.

Cash flow provided by financing activities for the six months ended June 30, 2025 increased by $294 million, compared to the same period in 2024. The increase was primarily due to higher net issuance of corporate commercial paper in the first quarter of 2025.

Committed credit facilities and maturity dates as at June 30, 2025 were as follows:

(*millions of dollars*)		**Amount**
Bank facilities:		
Corporate [1, 2]		**1,039**
Corporate [1]	US Dollars	**750**
Lower Mattagami Energy Limited Partnership [3]		**460**
OPG Eagle Creek Holdings LLC and subsidiaries	US Dollars	**20**
Ontario Financing Authority facility [2]		**1,250**
Ontario Electricity Financial Corporation facility [2]		**750**

[1] Certain corporate credit facilities contain a sustainability-linked feature that allows reduced pricing if the Company meets certain sustainability targets.
[2] Represents amounts available under the facility net of debt issuances.
[3] Letter of credit of $60 million was outstanding under this facility as at June 30, 2025.

Short-term debt, letters of credit and guarantees were as follows:

	As At	
(millions of dollars)	**June 30 2025**	**December 31 2024**
Lower Mattagami Energy Limited Partnership	**200**	215
Corporate commercial paper	**694**	-
Total short-term debt	**894**	215
Letters of credit	**734**	504
Guarantees	**-**	30

As at June 30, 2025, a total of $734 million of letters of credit had been issued. This included $314 million for the supplementary pension plans, $267 million for general corporate purposes, $60 million for Lower Mattagami Energy Limited Partnership, $44 million for Atura Power, $20 million for Eagle Creek and its subsidiaries, $14 for UMH Energy Partnership, $9 million for LEP and its subsidiaries, $5 million for PowerON Energy Solutions LP and $1 million for PSS Generating Station Limited Partnership.

Long-term debt balances were as follows:

	As At	
(millions of dollars)	**June 30 2025**	**December 31 2024**
Medium Term Notes payable	**6,550**	5,950
Senior notes payable under corporate credit facilities	**3,031**	2,859
Project financing	**2,888**	2,916
Other	**25**	25
Total long-term debt [1]	**12,494**	11,750

[1] Excludes the impact of fair value premium or discount and unamortized bond issuance fees.

BALANCE SHEET HIGHLIGHTS

Highlights of OPG's interim consolidated financial position are noted below:

(millions of dollars)	As At June 30 2025	As At December 31 2024
Property, plant and equipment – net The increase was primarily due to capital expenditures, partially offset by depreciation expense. Further details on capital expenditures can be found in the section, *Highlights* under the heading, *Capital Expenditures.*	**38,310**	36,131
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)* The increase was primarily due to earnings recognized on the Nuclear Segregated Funds, partially offset by reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities from the Nuclear Segregated Funds.	**22,864**	22,412
Short-term debt The increase was primarily due to net issuances of corporate commercial paper.	**894**	215
Long-term debt *(current and non-current portions)* The increase was due to net issuances under the Company's Medium Term Note Program and corporate credit facilities.	**12,445**	11,707
Fixed asset removal and nuclear waste management liabilities The increase was primarily a result of accretion expense, partially offset by expenditures on fixed asset removal and nuclear waste management activities.	**26,352**	26,042

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's consolidated financial statements or are recorded in the Company's consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to OPG's audited consolidated financial statements as at and for the year ended December 31, 2024. OPG's critical accounting policies are consistent with those noted in OPG's 2024 annual MD&A.

RISK MANAGEMENT

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements* at the beginning of the MD&A. The following section provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2024 annual MD&A in the section, *Risk Management*.

Risks to Achieving Operational Excellence

Tariffs and Trade Environment

Given the highly interconnected nature of the Canadian and US economies, trade and other impacts of tariffs between the two countries could disproportionately impact the Canadian economy. These impacts are expected to increase procurement costs of certain materials for OPG's projects and operations, and may result in supply chain disruptions if there are further restrictions placed on international trade. The economic impacts of the trade disputes could also impact demand for electricity in Ontario. The Company continues to actively identify procurements and supplier relationships that are now subject to tariffs, and, where possible, is pursuing alternate suppliers to reduce exposure to tariffs. OPG will continue to monitor changing trade and geopolitical landscapes and refine mitigation strategies as needed.

Risks to Maintaining Financial Strength

Credit

The Company's credit risk exposure is a function of its electricity sales, trading and hedging activities, and treasury activities including investing and commercial transactions with various suppliers of goods and services. OPG's credit risk exposure relating to energy market transactions as at June 30, 2025 was $641 million, including $561 million with the IESO. OPG continues to consider overall credit risk exposure relating to electricity sales to be low, as the majority of sales are through the IESO-administered market in Ontario.

Commodity Markets

Changes in the market prices of fuels used to produce electricity can adversely impact OPG's earnings and cash flow provided by operating activities. To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts. The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of electricity generation and supply mix and, as such, are subject to change as these forecasts are updated.

	2025 [1]	2026	2027
Estimated fuel requirements hedged *(%)* [2]	100	82	85

[1] Based on actual fuel requirements hedged for the six months ended June 30, 2025 and forecast for the remainder of the year.
[2] Represents the approximate portion of megawatt-hour (MWh) of expected electricity generation (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric, thermal and combined cycle) for which the price of fuel is fixed, or for which the Company has entered into contractual arrangements to secure the price of fuel or secure the recovery of fuel costs. In the case of regulated and contracted hydroelectric electricity generation in Ontario, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear, thermal and combined cycle) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Electricity Markets

OPG's revenue can be impacted by external factors related to electricity markets. In October 2024, the IESO approved market rules and design required to operationalize the Market Renewal Program, an IESO initiative to redesign the Ontario's electricity markets. The renewed electricity markets were launched on May 1, 2025. OPG has redesigned and updated its internal systems and processes to effectively participate in the new market. The Market Renewal Program is not expected to have a material impact on OPG's net income.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One Limited (Hydro One), the IESO and the OEFC. Transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions were as follows:

	Three Months Ended June 30			
	2025		2024	
(millions of dollars)	**Income**	**Expense**	**Income**	**Expense**
Hydro One				
Electricity sales	**5**	**-**	4	-
Services	**-**	**2**	-	2
Dividends	**1**	**-**	1	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**158**	-	35
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**216**	-	46
Hydroelectric gross revenue charge	**-**	**33**	-	31
OEFC				
Hydroelectric gross revenue charge	**-**	**58**	-	58
Interest expense on long-term notes	**-**	**22**	-	22
Income taxes	**-**	**168**	-	93
Property taxes	**-**	**4**	-	3
IESO				
Electricity related revenue	**1,893**	**-**	1,448	-
Fair Hydro Trust				
Interest income	**8**	**-**	8	-
	1,907	**661**	1,461	290

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of any excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at June 30, 2025 and December 31, 2024, the Nuclear Segregated Funds were reported net of amounts due to the Province of $10,687 million and $10,236 million, respectively.

	Six Months Ended June 30			
	2025		2024	
(millions of dollars)	**Income**	**Expense**	**Income**	**Expense**
Hydro One				
Electricity sales	**15**	**-**	10	-
Services	**-**	**8**	-	4
Dividends	**2**	**-**	2	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**193**	-	448
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**258**	-	597
Hydroelectric gross revenue charge	**-**	**63**	-	61
OEFC				
Hydroelectric gross revenue charge	**-**	**95**	-	99
Interest expense on long-term notes	**-**	**43**	-	45
Income taxes	**-**	**341**	-	163
Property taxes	**-**	**7**	-	6
IESO				
Electricity-related revenue	**3,936**	**-**	3,031	-
Fair Hydro Trust				
Interest income	**16**	**-**	16	-
	3,969	**1,008**	3,059	1,423

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of any excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at June 30, 2025 and December 31, 2024, the Nuclear Segregated Funds were reported net of amounts due to the Province of $10,687 million and $10,236 million, respectively.

Balances between OPG and its related parties are summarized below:

(millions of dollars)	**June 30 2025**	**December 31 2024**
Receivables from related parties		
Hydro One	**2**	3
IESO – Electricity related receivables	**561**	608
Fair Hydro Trust	**4**	4
OEFC	**9**	-
Province of Ontario	**6**	1
Loan receivable		
Fair Hydro Trust	**901**	902
Equity securities		
Hydro One shares	**152**	159
Accounts payable, accrued charges and other payables		
Hydro One	**1**	3
OEFC	**85**	85
Province of Ontario	**3**	10
Long-term debt (including current portion)		
Notes payable to OEFC	**2,100**	2,100

OPG may hold Province of Ontario bonds and treasury bills in the Nuclear Segregated Funds and the OPG registered pension plan. As at June 30, 2025, the Nuclear Segregated Funds held $1,743 million of Province of Ontario bonds (December 31, 2024 – $1,740 million) and $12 million of Province of Ontario treasury bills (December 31, 2024 – $8 million). As of June 30, 2025, the OPG registered pension plan held $310 million of Province of Ontario bonds (December 31, 2024 − $327 million) and $11 million of Province of Ontario treasury bills (December 31, 2024 – $9 million). These Province of Ontario bonds and treasury bills are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

INTERNAL CONTROL OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for Internal Control over Financial Reporting (ICFR) and for its Disclosure Controls and Procedures (DC&P). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact on the financial statements.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected financial information for each of the eight most recently completed quarters. This information is derived from OPG's unaudited interim consolidated financial statements and the audited annual consolidated financial statements, and has been prepared in accordance with US GAAP.

(millions of dollars – except where noted) *(unaudited)*	**June 30 2025**	**March 31 2025**	**December 31 2024**	**September 30 2024**
Electricity generation (*TWh*)	**21.9**	23.5	20.4	21.7
Revenue	**2,032**	2,157	1,838	1,891
Net income	**547**	509	232	383
Less: Net income attributable to non-controlling interest	**6**	4	4	4
Net income attributable to the Shareholder	**541**	505	228	379
Earnings per share, attributable to the Shareholder *(dollars)*	**$1.97**	$1.84	$0.83	$1.38

(millions of dollars – except where noted) *(unaudited)*	**June 30 2024**	**March 31 2024**	**December 31 2023**	**September 30 2023**
Electricity generation (*TWh*)	18.9	21.1	20.8	20.9
Revenue	1,691	1,767	1,894	1,882
Net income	166	225	454	449
Less: Net income attribute to the non-controlling interest	6	4	4	5
Net income attributable to the Shareholder	160	221	450	444
Earnings per share, attributable to the Shareholder *(dollars)*	$0.58	$0.80	$1.64	$1.62

[1] Earnings per share was calculated using the weighted average number of shares outstanding of 274.6 million for all periods presented. There were no dilutive securities during any of the periods presented.

KEY OPERATING PERFORMANCE INDICATORS AND NON-GAAP FINANCIAL MEASURES

Key Operating Performance Measures

OPG evaluates the performance of its generating stations using a number of key indicators. Key operating performance indicators aligned with corporate business imperatives include measures of production reliability, cost effectiveness, environmental performance and safety performance. Certain of the measures used vary depending on the generating technology.

Nuclear Unit Capability Factor

The Nuclear Unit Capability Factor is a key measure of nuclear station performance. It measures the amount of energy that the unit(s) generated over a period of time, adjusted for externally imposed constraints such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation. Capability factors are primarily affected by planned and unplanned outages. An outage day represents a single unit being offline or derated for an amount of time equivalent to one day. By industry definition, capability factors exclude production losses beyond plant management's control, such as grid-related unavailability. The nuclear Unit Capability Factor also excludes unit(s) during the period in which they are undergoing refurbishment.

Hydroelectric Availability

Hydroelectric Availability represents the percentage of time the generating unit is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period, weighted by unit capacity.

Thermal Equivalent Forced Outage Rate

Equivalent forced outage rate is an index of the reliability of a generating unit at OPG's wholly-owned thermal stations. It is measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

Thermal Availability

Thermal Availability represents the percentage of time a generating unit at Atura Power's combined cycle plants is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period, averaged by the number of facilities owned and operated through Atura Power. The measure is calculated on a three-year rolling average basis.

Other Key Indicators

OPG has also identified certain environmental and safety performance measures, which are discussed in the section, *Environmental, Social, Governance and Sustainability*.

Non-GAAP Financial Performance Measures

In addition to net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in this MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance and ensure availability of cost-effective funding. These non-GAAP financial measures have not been presented as an alternative to net income or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) Earnings before interest, income taxes, depreciation and amortization is defined as net income before net interest expense, income tax expense and depreciation and amortization expenses.

(2) Gross margin is defined as revenue less fuel expense.

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ONTARIO POWER GENERATION INC.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

JUNE 30, 2025

ONTARIO POWER GENERATION

INTERIM CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(millions of dollars – except where noted)	Three Months Ended June 30		Six Months Ended June 30	
	2025	**2024**	**2025**	**2024**
Revenue	**2,032**	1,691	**4,189**	3,458
Fuel expense	**284**	240	**656**	493
Gross margin	**1,748**	1,451	**3,533**	2,965
Operations, maintenance and administration expenses	**660**	840	**1,371**	1,710
Depreciation and amortization expenses	**355**	304	**710**	604
Accretion on fixed asset removal and nuclear waste management liabilities	**311**	305	**624**	611
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(280)**	(274)	**(564)**	(545)
Property taxes	**12**	12	**25**	24
	1,058	1,187	**2,166**	2,404
Income before other (gains) losses, interest and income taxes	**690**	264	**1,367**	561
Other (gains) losses	**(9)**	21	**(25)**	18
Income before interest and income taxes	**699**	243	**1,392**	543
Net interest expense *(Note 4)*	**52**	51	**108**	96
Income before income taxes	**647**	192	**1,284**	447
Income tax expense	**100**	26	**228**	56
Net income	**547**	166	**1,056**	391
Net income attributable to the Shareholder	**541**	160	**1,046**	381
Net income attributable to non-controlling interest	**6**	6	**10**	10
Basic and diluted earnings per share *(dollars)* [1]	**1.97**	0.58	**3.81**	1.39

[1] The weighted average number of shares outstanding as at June 30, 2025 and 2024 was 274.6 million. There were no dilutive securities during the three and six month periods ended June 30, 2025 and 2024.

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

(millions of dollars)	Three Months Ended June 30		Six Months Ended June 30	
	2025	**2024**	**2025**	**2024**
Net income	**547**	166	**1,056**	391
Other comprehensive (loss) income, net of income taxes *(Note 7)*				
Reclassification to income of amounts related to pension and other post-employment benefits [1]	**(1)**	-	**(1)**	(1)
Reclassification to income of amounts related to derivatives designated as cash flow hedges [2]	**-**	(1)	**-**	(2)
Net gain (loss) on derivatives designated as cash flow hedges [3]	**2**	8	**(4)**	1
Currency translation adjustment	**(109)**	20	**(112)**	69
Other comprehensive (loss) income for the period	**(108)**	27	**(117)**	67
Comprehensive income	**439**	193	**939**	458
Comprehensive income attributable to the Shareholder	**433**	187	**929**	448
Comprehensive income attributable to non-controlling interest	**6**	6	**10**	10

[1] Net of income tax recovery of nil for each of the three and six month periods ended June 30, 2025. Net of income tax recovery of nil for each of the three and six month periods ended June 30, 2024.
[2] Net of income tax recovery of nil for each of the three and six month periods ended June 30, 2025. Net of income tax recovery of $1 million for each of the three and six month periods ended June 30, 2024.
[3] Net of income tax expense of $1 million and recovery of $1 million for the three and six month periods ended June 30, 2025, respectively. Net of income tax expense of $2 million and nil for the three and six month periods ended June 30, 2024, respectively.

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(millions of dollars)	Six Months Ended June 30 2025	2024
Operating activities		
Net income	**1,056**	391
Adjust for non-cash items:		
Depreciation and amortization expenses	**710**	604
Accretion on fixed asset removal and nuclear waste management liabilities	**624**	611
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(564)**	(545)
Pension and other post-employment benefit costs *(Note 8)*	**155**	182
Deferred income tax (recovery) expense	**(30)**	18
Regulatory assets and regulatory liabilities	**38**	(57)
Other losses	**3**	21
Other	**(10)**	(8)
Expenditures on fixed asset removal and nuclear waste management	**(516)**	(225)
Reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management	**103**	121
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	**(156)**	(150)
Net changes to other long-term assets and long-term liabilities	**83**	156
Net changes in non-cash working capital balances *(Note 13)*	**133**	(15)
Cash flow provided by operating activities	**1,629**	1,104
Investing activities		
Investment in property, plant and equipment and intangible assets *(Note 12)*	**(2,616)**	(1,730)
Acquisition of Lightstar Renewables and Lightstar Operations One	**-**	(131)
Proceeds from sale of interest in joint venture	**11**	-
Cash flow used in investing activities	**(2,605)**	(1,861)
Financing activities		
Issuance of long-term debt *(Note 4)*	**1,167**	1,357
Repayment of long-term debt *(Note 4)*	**(401)**	(601)
Issuance of short-term debt *(Note 5)*	**2,374**	1,795
Repayment of short-term debt *(Note 5)*	**(1,695)**	(1,395)
Equity investment from non-controlling interest	**7**	3
Distribution to non-controlling interest	**(9)**	(10)
Cash flow provided by financing activities	**1,443**	1,149
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**(7)**	6
Net increase in cash, cash equivalents and restricted cash	**460**	398
Cash, cash equivalents and restricted cash, beginning of period	**1,363**	1,481
Cash, cash equivalents and restricted cash, end of period	**1,823**	1,879

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	June 30 2025	December 31 2024
Assets		
Current assets		
Cash, cash equivalents and restricted cash	**1,823**	1,363
Equity securities	**152**	159
Receivables from related parties	**582**	616
Nuclear fixed asset removal and nuclear waste management funds	**504**	283
Fuel inventory	**402**	297
Materials and supplies	**181**	145
Regulatory assets *(Note 3)*	**540**	540
Prepaid expenses	**249**	292
Other current assets	**198**	388
	4,631	4,083
Property, plant and equipment	**53,967**	51,290
Less: accumulated depreciation	**15,657**	15,159
	38,310	36,131
Intangible assets	**1,047**	1,029
Less: accumulated amortization	**482**	439
	565	590
Goodwill	**218**	230
Other assets		
Nuclear fixed asset removal and nuclear waste management funds	**22,360**	22,129
Loan receivable from related party	**901**	902
Long-term materials and supplies	**328**	355
Regulatory assets *(Note 3)*	**4,357**	4,367
Investments subject to significant influence	**41**	52
Pension assets	**38**	-
Other long-term assets	**168**	137
	28,193	27,942
	71,917	68,976

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	June 30 2025	December 31 2024
Liabilities		
Current liabilities		
Accounts payable, accrued charges and other payables	**2,108**	2,068
Short-term debt *(Note 5)*	**894**	215
Long-term debt due within one year *(Note 4)*	**925**	604
Regulatory liabilities *(Note 3)*	**246**	246
	4,173	3,133
Long-term debt *(Note 4)*	**11,520**	11,103
Other liabilities		
Fixed asset removal and nuclear waste management liabilities *(Note 6)*	**26,352**	26,042
Pension liabilities	**-**	46
Other post-employment benefit liabilities	**2,768**	2,716
Long-term accounts payable and accrued charges	**424**	382
Deferred revenue	**350**	355
Deferred income taxes	**2,557**	2,461
Regulatory liabilities *(Note 3)*	**1,012**	939
	33,463	32,941
Equity		
Common shares [1]	**5,126**	5,126
Class A shares [2]	**787**	787
Contributed surplus	**27**	28
Retained earnings	**16,515**	15,469
Accumulated other comprehensive income *(Note 7)*	**76**	193
Equity attributable to the Shareholder	**22,531**	21,603
Equity attributable to non-controlling interest	**230**	196
Total equity	**22,761**	21,799
	71,917	68,976

[1] 256,300,010 common shares outstanding at a stated value of $5,126 million as at June 30, 2025 and December 31, 2024.
[2] 18,343,815 Class A shares outstanding at a stated value of $787 million as at June 30, 2025 and December 31, 2024.

Commitments and Contingencies *(Notes 4, 5, 8 and 11)*

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY (UNAUDITED)

(millions of dollars)	Six Months Ended June 30 2025	2024
Common shares	**5,126**	5,126
Class A shares	**787**	787
Contributed surplus		
Balance at beginning of period	**28**	30
Reclassification to income of amounts related to gain on deconsolidation of Fair Hydro Trust	**(1)**	(1)
Balance at end of period	**27**	29
Retained earnings		
Balance at beginning of period	**15,469**	14,481
Net income attributable to the Shareholder	**1,046**	381
Balance at end of period	**16,515**	14,862
Accumulated other comprehensive income, net of income taxes *(Note 7)*		
Balance at beginning of period	**193**	(15)
Other comprehensive (loss) income	**(117)**	67
Balance at end of period	**76**	52
Equity attributable to the Shareholder	**22,531**	20,856
Equity attributable to non-controlling interest		
Balance at beginning of period	**196**	182
Income attributable to non-controlling interest	**10**	10
Equity investment from non-controlling interest	**33**	8
Distribution to non-controlling interest	**(9)**	(10)
Balance at end of period	**230**	190
Total equity	**22,761**	21,046

See accompanying notes to the interim consolidated financial statements

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. BASIS OF PRESENTATION

These interim consolidated financial statements for the three and six month periods ended June 30, 2025 and 2024 include the accounts of Ontario Power Generation Inc. (OPG or the Company) and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control and attributes the results to its sole shareholder, the Province of Ontario (the Province or the Shareholder). These interim consolidated financial statements have been prepared and presented in accordance with United States generally accepted accounting principles (US GAAP). These interim consolidated financial statements do not contain all of the disclosures required by US GAAP for annual financial statements. Accordingly, they should be read in conjunction with the annual consolidated financial statements of the Company as at and for the year ended December 31, 2024.

All dollar amounts are presented in Canadian dollars, unless otherwise noted. Certain 2024 comparative amounts have been reclassified from consolidated financial statements previously presented to conform to the 2025 interim consolidated financial statement presentation.

Seasonal Variations

OPG's quarterly electricity generation from the Regulated – Hydroelectric Generation, Contracted Hydroelectric and Other Generation, and Atura Power business segments is affected by changes in grid-supplied electricity demand. Changes in grid-supplied electricity demand are primarily caused by variations in seasonal weather conditions, changes in economic conditions, the impact of small-scale generation embedded in distribution networks, and the impact of conservation efforts. Historically, there has been greater electricity demand in Ontario during the winter and summer months due to heating and air conditioning demands.

OPG's quarterly electricity generation from hydroelectric facilities is impacted by weather conditions that affect water flows. Historically, there have been higher water flows in the second quarter as a result of snow and ice melt entering the river systems. The financial impact of variability in water flows on the Regulated – Hydroelectric Generation business segment is mitigated by regulatory deferral and variance accounts (regulatory accounts) authorized by the Ontario Energy Board (OEB).

The financial impact of variability in electricity generation from the Contracted Hydroelectric and Other Generation business segment and the Atura Power business segment is mitigated by the terms of the applicable Energy Supply Agreements with the Independent Electricity System Operator (IESO) for the contracted generating facilities in Ontario.

2. SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

The accounting policies followed in the presentation of these interim consolidated financial statements are consistent with those of the previous fiscal year.

Recent Accounting Pronouncements Not Yet Adopted

Improvements to Income Tax Disclosures

In December 2023, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2023-09, *Improvements to Income Tax Disclosures* (ASU 2023-09), an update to Topic 740, *Income Taxes*. The purpose of ASU 2023-09 is to enhance the transparency and decision usefulness of income tax disclosures through increasing disclosure requirements related to the rate reconciliation and income taxes paid information. The update requires specific categories to be disclosed in the rate reconciliation and additional information for reconciling items that meet a quantitative threshold. The update also requires that entities disclose income taxes paid disaggregated by federal, provincial and foreign taxes and by individual jurisdiction in which income tax paid exceeds five percent of total income taxes paid. The update is effective for annual periods beginning after December 15, 2024. The adoption of the standard update is not expected to have a material impact on the disclosures contained in the Company's annual and interim consolidated financial statements.

Disaggregation of Income Statement Expenses

In November 2024, the FASB issued ASU 2024-03, *Disaggregation of Income Statement Expenses*, an update to Subtopic 220-40, *Income Statement – Reporting Comprehensive Income – Expense Disaggregation Disclosures*. The purpose of the standard update is to improve the disclosures about a public business entity's expenses by requiring more detailed information about the types of expenses (including purchases of inventory and employee compensation) included within consolidated income statement expense captions. The update is effective for fiscal years beginning after December 15, 2026 and interim periods beginning after December 15, 2027, with early adoption permitted. The standard update is to be applied prospectively with the option for retrospective application. The Company is currently evaluating the impact of adoption of the standard update on the disclosures contained within the Company's annual and interim consolidated financial statements.

Determining the Accounting Acquirer in the Acquisition of a Variable Interest Entity

In May 2025, the FASB issued ASU 2025-03, *Determining the Accounting Acquirer in the Acquisition of a Variable Interest Entity*, an update to Topic 805, *Business Combinations* and Topic 810, *Consolidation*. The update amends the guidance for determining the accounting acquirer for a transaction effected primarily by exchanging equity interests in which the legal acquiree is a variable interest entity that meets the definition of a business. The update is effective for fiscal years beginning after December 15, 2026, including interim periods within those fiscal years, with early adoption permitted. The standard update is to be applied prospectively. The Company is currently evaluating the impact of adoption of the standard update on the disclosures contained within the Company's annual and interim consolidated financial statements.

3. REGULATORY ASSETS AND REGULATORY LIABILITIES

The regulatory assets and regulatory liabilities consist of the following:

As at *(millions of dollars)*	June 30 2025	December 31 2024
Regulatory assets		
Deferral and variance accounts authorized by OEB or Ontario Regulation 53/05		
Rate Smoothing Deferral Account	**690**	677
Nuclear Liability Deferral Account	**483**	520
Capacity Refurbishment Variance Account	**456**	460
Hydroelectric Surplus Baseload Generation Variance Account	**271**	307
Pension & OPEB Cash Versus Accrual Differential Deferral Account	**268**	376
Pickering B Extension Variance Account	**151**	131
Nuclear Development Variance Account	**71**	85
Other deferral and variance accounts [1]	**172**	174
	2,562	2,730
Deferred income taxes	**2,281**	2,151
Other	**54**	26
Total regulatory assets	**4,897**	4,907
Less: current portion	**540**	540
Non-current regulatory assets	**4,357**	4,367
Regulatory liabilities		
Deferral and variance accounts authorized by OEB or Ontario Regulation 53/05		
Pension and OPEB Cost Variance Account	**422**	411
Pension & OPEB Cash Payment Variance Account	**269**	321
Hydroelectric Water Conditions Variance Account	**190**	173
Bruce Lease Net Revenues Variance Account	**119**	60
Nuclear Deferral and Variance Over/Under Recovery Variance Account	**79**	61
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges Variance Account	**60**	51
Other deferral and variance accounts [2]	**112**	92
	1,251	1,169
Pension and OPEB Regulatory Liability *(Note 8)*	**7**	16
Total regulatory liabilities	**1,258**	1,185
Less: current portion	**246**	246
Non-current regulatory liabilities	**1,012**	939

[1] Represents amounts for the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, Clarington Corporate Campus Deferral Account, Fitness for Duty Deferral Account, Pickering Closure Costs Deferral Account, Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account, Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account and Impact Resulting from Changes to Pickering Station End-of-Life Dates Deferral Account (December 31, 2017).

[2] Represents amounts for the Income and Other Taxes Variance Account, SR&ED ITC Variance Account, Ancillary Services Net Revenue Variance Account and Sale of Unprescribed Kipling Site Deferral Account.

Effective July 1, 2025, the Province amended *Ontario Regulation 53/05* to clarify the scope of the Pickering B Extension Variance Account such that OPG can record costs incurred on or after January 1, 2024 to preserve the ability to operate Units 5 to 8 of the Pickering nuclear generating station upon refurbishment for future recovery, subject to review by the OEB.

In April 2025, the Province released a proposal for potential amendments to *Ontario Regulation 53/05* to allow for the creation of a new variance account to record pre-development expenses for proposed hydroelectric projects by OPG for future recovery, subject to review by the OEB. The comment period for the proposal ended on June 13, 2025.

Under the current OEB rate-setting framework, OPG begins recovering costs through regulated prices once projects are placed in-service. In May 2025, the Province proposed potential changes in regulations that would establish a new mechanism for concurrent cost recovery to allow OPG to recover debt interest during the construction periods of the Darlington New Nuclear Project (DNNP) and the Pickering Refurbishment project (if the project is approved to proceed). The proposed change would also prescribe a new OEB-regulated generator and establish the applicable rate-setting framework to enable OPG to enter into commercial partnerships for the DNNP. The comment period for the proposal ended on June 26, 2025.

4. LONG-TERM DEBT AND NET INTEREST EXPENSE

Long-term debt consists of the following:

As at *(millions of dollars)*	**June 30 2025**	**December 31 2024**
Medium Term Note Program senior notes	**6,550**	5,950
Senior notes payable under corporate credit facilities	**3,031**	2,859
Lower Mattagami Energy Limited Partnership senior notes	**1,995**	1,995
PSS Generating Station Limited Partnership senior notes	**245**	245
UMH Energy Partnership senior notes	**159**	160
OPG Eagle Creek Holdings LLC and subsidiaries senior notes	**489**	516
Other	**25**	25
	12,494	11,750
Less: net fair value premium	**(2)**	-
Less: unamortized bond issuance fees	**(47)**	(43)
Less: amounts due within one year	**(925)**	(604)
Long-term debt	**11,520**	11,103

On March 13, 2025, OPG issued $1 billion of green bonds under its Sustainable Finance Framework, through its Medium Term Note Program. The issuance consisted of $500 million of senior notes maturing in March 2035, with a coupon interest rate of 4.32 percent and $500 million of senior notes maturing in March 2055, with a coupon interest rate of 4.87 percent. The net proceeds from the issuance were used to finance or re-finance Eligible Green Projects as defined under the Sustainable Finance Framework.

OPG repaid long-term debt of $400 million under the Company's Medium Term Note Program during the six months ended June 30, 2025.

For the six months ended June 30, 2025, net issuance of long-term debt under the Company's corporate credit facilities totalled $172 million (six months ended June 30, 2024 – net repayment of $236 million), which comprised issuances of $172 million (six months ended June 30, 2024 – repayment of $400 million) and repayment of nil (six months ended June 30, 2024 – issuances of $164 million).

Net Interest Expense

The following table summarizes the net interest expense:

(millions of dollars)	Three Months Ended June 30		Six Months Ended June 30	
	2025	**2024**	**2025**	**2024**
Interest on long-term debt	**119**	94	**227**	186
Interest on short-term debt	**8**	8	**14**	12
Interest income	**(22)**	(16)	**(42)**	(39)
Interest capitalized to property, plant and equipment and intangible assets	**(46)**	(33)	**(76)**	(61)
Interest related to regulatory assets and regulatory liabilities [1]	**(7)**	(2)	**(15)**	(2)
Net interest expense	**52**	51	**108**	96

[1] Includes interest to recognize the cost of financing regulatory account balances as authorized by the OEB, and interest costs deferred in certain regulatory accounts.

5. SHORT-TERM DEBT

Committed credit facilities and maturity dates as at June 30, 2025 were as follows:

(millions of dollars)		**Amount**	**Maturity**
Bank facilities:			
Corporate		**1,039**	August 2025 and May 2030 [1,2]
Corporate	US Dollars	**750**	May 2026 [3]
Lower Mattagami Energy Limited Partnership		**460**	June 2029 [4]
OPG Eagle Creek Holdings LLC and subsidiaries	US Dollars	**20**	October 2028
Ontario Financing Authority facility		**1,250**	December 2029 [1]
Ontario Electricity Financial Corporation facility		**750**	December 2026 [1]

[1] Represents amounts available under the facility net of debt issuances.
[2] Of the total credit facilities, $39 million is expected to mature in August 2025 and is available to finance certain expenditures of the DNNP, subject to certain conditions, and $1,000 million matures in May 2030.
[3] The facility has a one-year extension option beyond the maturity date of May 2026.
[4] A letter of credit of $60 million was outstanding under this facility as at June 30, 2025.

Short-term debt consists of the following:

As at *(millions of dollars)*	**June 30 2025**	**December 31 2024**
Lower Mattagami Energy Limited Partnership	**200**	215
Corporate commercial paper	**694**	-
Short-term debt	**894**	215

As at June 30, 2025, a total of $734 million of letters of credit had been issued (December 31, 2024 – $504 million). As at June 30, 2025, this included $314 million for the supplementary pension plans, $267 million for general corporate purposes, $60 million for Lower Mattagami Energy Limited Partnership, $44 million for Atura Power, $20 million for OPG Eagle Creek Holdings LLC and its subsidiaries, $14 million for UMH Energy Partnership, $9 million for Laurentis Energy Partners and its subsidiaries, $5 million for PowerON Energy Solutions LP and $1 million for PSS Generating Station Limited Partnership.

The weighted average interest rate on the short-term debt as at June 30, 2025 is 2.88 percent (December 31, 2024 – 3.71 percent).

6. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

Liabilities for fixed asset removal and nuclear waste management on a present value basis consist of the following:

As at *(millions of dollars)*	June 30 2025	December 31 2024
Liability for used nuclear fuel management	**16,254**	15,991
Liability for nuclear decommissioning and nuclear low and intermediate level waste management	**9,833**	9,782
Liability for non-nuclear fixed asset removal	**265**	269
Fixed asset removal and nuclear waste management liabilities	**26,352**	26,042

7. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in the balance of each component of accumulated other comprehensive income (loss) (AOCI), net of income taxes, were as follows:

	Six Months Ended June 30, 2025			
(millions of dollars)	Unrealized Gains and Losses on Cash Flow Hedges	Pension and OPEB	Currency Translation Adjustment	Total
Balance, beginning of period	**5**	**6**	**182**	**193**
Net loss on cash flow hedges	**(4)**	**-**	**-**	**(4)**
Amounts reclassified from AOCI	**-**	**(1)**	**-**	**(1)**
Translation of foreign operations	**-**	**-**	**(112)**	**(112)**
Other comprehensive loss for the period	**(4)**	**(1)**	**(112)**	**(117)**
Balance, end of period	**1**	**5**	**70**	**76**

	Six Months Ended June 30, 2024			
(millions of dollars)	Unrealized Gains and Losses on Cash Flow Hedges	Pension and OPEB	Currency Translation Adjustment	Total
Balance, beginning of period	9	(33)	9	(15)
Net gain on cash flow hedges	1	-	-	1
Amounts reclassified from AOCI	(2)	(1)	-	(3)
Translation of foreign operations	-	-	69	69
Other comprehensive (loss) income for the period	(1)	(1)	69	67
Balance, end of period	8	(34)	78	52

The significant amounts reclassified out of each component of AOCI, net of income taxes, were as follows:

	Amount Reclassified from AOCI		
(millions of dollars)	**Three Months Ended June 30, 2025**	**Six Months Ended June 30, 2025**	**Statement of Income Line Item**
Amortization of amounts related to pension and OPEB			
Net actuarial gains, net of past service costs	**(1)**	**(1)**	See (1) below
Income tax recovery	**-**	**-**	Income tax expense
	(1)	**(1)**	
Total reclassifications for the period	**(1)**	**(1)**	

	Amount Reclassified from AOCI		
(millions of dollars)	**Three Months Ended June 30, 2024**	**Six Months Ended June 30, 2024**	**Statement of Income Line Item**
Amortization of amounts related to cash flow hedges			
Losses	(2)	(3)	Revenue and Net interest expense
Income tax expense	1	1	Income tax expense
	(1)	(2)	
Amortization of amounts related to pension and OPEB			
Net actuarial gains, net of past service costs	-	(1)	See (1) below
Income tax recovery	-	-	Income tax expense
	-	(1)	
Total reclassifications for the period	(1)	(3)	

[1] These AOCI components are included in the computation of pension and OPEB costs (see Note 8 for additional details).

Existing pre-tax net losses for derivatives of nil deferred in AOCI as at June 30, 2025 are expected to be reclassified to net income within the next 12 months.

8. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

OPG's pension and other post-employment benefit (OPEB) costs for the three months ended June 30, 2025 and 2024 were as follows:

	Registered Pension Plans		Supplementary Pension Plans		Other Post-Employment Benefits	
(millions of dollars)	**2025**	**2024**	**2025**	**2024**	**2025**	**2024**
Components of cost recognized for the period						
Current service costs	**74**	77	**3**	2	**26**	25
Interest on projected benefit obligation	**191**	198	**4**	4	**32**	32
Expected return on plan assets, net of expenses	**(268)**	(258)	**-**	-	**-**	-
Amortization of past service costs [1]	**-**	-	**-**	-	**1**	-
Amortization of net actuarial loss (gain) [1]	**-**	-	**1**	1	**(7)**	(7)
Costs recognized [2]	**(3)**	17	**8**	7	**52**	50

[1] The net impact of amortization of past service costs and net actuarial loss (gain) is recognized as an increase (decrease) to other comprehensive income. This decrease for the three months ended June 30, 2025 was partially offset by a decrease in the Pension and OPEB Regulatory Liability of $4 million (three months ended June 30, 2024 – an increase in the Pension and OPEB Regulatory Asset of $6 million).

[2] These pension and OPEB costs for the three months ended June 30, 2025 exclude the net addition of costs of $20 million resulting from the recognition of changes in the regulatory assets or liabilities for the Pension & OPEB Cost Variance Account, the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account (three months ended June 30, 2024 – net addition of costs of $17 million).

OPG's pension and OPEB costs for the six months ended June 30, 2025 and 2024 were as follows:

	Registered Pension Plans		Supplementary Pension Plans		Other Post-Employment Benefits	
(millions of dollars)	**2025**	**2024**	**2025**	**2024**	**2025**	**2024**
Components of cost recognized for the period						
Current service costs	**148**	153	**5**	4	**52**	50
Interest on projected benefit obligation	**383**	396	**9**	8	**64**	65
Expected return on plan assets, net of expenses	**(537)**	(516)	**-**	-	**-**	-
Amortization of past service costs [1]	**-**	-	**-**	-	**2**	1
Amortization of net actuarial loss (gain) [1]	**-**	-	**2**	2	**(14)**	(15)
Costs recognized [2]	**(6)**	33	**16**	14	**104**	101

[1] The net impact of amortization of past service costs and net actuarial loss (gain) is recognized as an increase (decrease) to other comprehensive income. This decrease for the six months ended June 30, 2025 was partially offset by a decrease in the Pension and OPEB Regulatory Liability of $9 million (six months ended June 30, 2024 – an increase in the Pension and OPEB Regulatory Asset of $11 million).

[2] These pension and OPEB costs for the six months ended June 30, 2025 exclude the net addition of costs of $41 million resulting from the recognition of changes in the regulatory assets or liabilities for the Pension & OPEB Cost Variance Account, the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account (six months ended June 30, 2024 – net addition of costs of $34 million).

9. RISK MANAGEMENT AND DERIVATIVES

OPG is exposed to risks related to changes in market interest rates on debt, movements in foreign currency that affect the Company's assets, liabilities and forecasted transactions, and fluctuations in commodity prices. Select derivative instruments are used to manage such risks. Derivatives are used as hedging instruments, as well as for trading purposes.

Interest Rates

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in interest rates. Interest rate risk for OPG arises with the need to refinance existing debt or undertake new financing. The management of these risks includes using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

Foreign Exchange

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as certain materials, services and fuels purchased for generating stations and major development projects, as well as debt issuances, may be denominated in, or tied to, US dollars. To manage this risk, the Company employs various financial instruments such as forwards and other derivative contracts, in accordance with approved corporate risk management policies. Additionally, volatility in the Canadian/US foreign exchange rate also impacts OPG's financial results from certain of its subsidiaries, whose operations are based exclusively in the United States (US).

Commodity Prices

OPG is exposed to fluctuations in commodity prices. Changes in the market prices of nuclear fuels, oil, gas and biomass used to produce electricity can adversely impact OPG's earnings and cash flow provided by operating activities. To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts.

A number of OPG's hydroelectric facilities in the US sell into the wholesale electricity market, and therefore are subject to volatility of wholesale electricity market pricing. Revenue from these facilities represents a small portion of OPG's overall revenue. The Company may enter into derivative instruments from time to time to further mitigate this risk.

Credit

The Company's credit risk exposure is primarily a function of its electricity and other sales. The majority of OPG's revenue is derived from electricity sales through the IESO administered market. Market participants in the IESO market provide collateral in accordance with the IESO prudential support requirements to cover funds that they might owe to the market. Although the credit exposure to the IESO represents a significant portion of OPG's accounts receivable, the risk is considered acceptable due to the IESO's primary role in the Ontario electricity market. The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts was $1 million as at June 30, 2025 (December 31, 2024 – less than $1 million).

The fair value of the derivative instruments totalled a net liability of $10 million as at June 30, 2025 (December 31, 2024 − net liability of $17 million).

10. FAIR VALUE MEASUREMENTS

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial assets and liabilities into three levels, based on the inputs used in measuring the fair value of the financial assets and liabilities. The fair value hierarchy has the following levels:

- Level 1: Valuation of inputs is based on unadjusted quoted market prices observed in active markets for identical assets or liabilities.
- Level 2: Valuation is based on inputs other than quoted prices under Level 1 that are observable for the asset or liability, either directly or indirectly.
- Level 3: Valuation is based on inputs for the asset or liability that are not based on observable market data.

The fair value of financial instruments traded in active markets is based on quoted market prices as at the interim consolidated balance sheet dates. A market is regarded as active if quoted prices are readily and regularly available from an exchange, dealer, broker, industry group, pricing service or regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's-length basis. The quoted market price used for financial assets held by OPG is the current bid price. These instruments are included in Level 1 and consist primarily of equity investments and fund investments.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing as at the interim consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives and fund investments. Various other fund investments are valued at the unit values supplied by the fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and, therefore, do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If all significant inputs required to fair value an instrument are observable, the instrument is included in Level 2.

If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. Specific valuation techniques are used to value these instruments. Significant Level 3 inputs include recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions and other relevant factors.

A summary of OPG's financial instruments and their fair value as at June 30, 2025 and December 31, 2024 was as follows:

	Fair Value		Carrying Value [1]		
(millions of dollars)	**2025**	**2024**	**2025**	**2024**	**Balance Sheet Line Item**
Nuclear Segregated Funds (includes current portion) [2]	**22,864**	22,412	**22,864**	22,412	Nuclear fixed asset removal and nuclear waste management funds
Loan receivable – from Fair Hydro Trust	**825**	828	**901**	902	Loan receivable from related party
Investment in Hydro One Limited Shares	**152**	159	**152**	159	Equity securities
Long-term debt (includes current portion)	**(9,867)**	(11,204)	**(12,445)**	(11,707)	Long-term debt
Other financial instruments	**156**	129	**156**	129	Various

[1] The carrying values of other financial instruments included in cash and cash equivalents, receivables from related parties, other current assets, short-term debt, and accounts payable, accrued charges and other payables approximate their fair values due to the immediate or short-term maturity of these financial instruments.

[2] The Nuclear Segregated Funds are comprised of the Decommissioning Segregated Fund and the Used Fuel Segregated Fund. OPG's fair value of the Nuclear Segregated Funds is set not to exceed an amount equal to the funding liability pursuant to the Ontario Nuclear Funds Agreement when the Nuclear Segregated Funds are in a surplus position.

The fair value of OPG's long-term debt issued under the Medium Term Note Program is based on indicative pricing from the market. The fair value of these debt instruments is based on Level 2 inputs. The fair value of all other long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs.

The following tables present financial assets and financial liabilities measured at fair value in accordance with the fair value hierarchy:

As at	June 30, 2025			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**6,772**	**7,280**	**-**	**14,052**
Investments measured at NAV [1]				**4,903**
				18,955
Due to Province				**(5,949)**
Used Fuel Segregated Fund, net				**13,006**
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**5,190**	**5,572**	**-**	**10,762**
Investments measured at NAV [1]				**3,834**
				14,596
Due to Province				**(4,738)**
Decommissioning Segregated Fund, net				**9,858**
Equity securities	**152**	**-**	**-**	**152**
Other financial assets	**96**	**-**	**98**	**194**
Liabilities				
Other financial liabilities	**(38)**	**-**	**-**	**(38)**

As at	December 31, 2024			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	7,030	6,676	-	13,706
Investments measured at NAV [1]				4,722
				18,428
Due to Province				(5,691)
Used Fuel Segregated Fund, net				12,737
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	5,362	5,156	-	10,518
Investments measured at NAV [1]				3,702
				14,220
Due to Province				(4,545)
Decommissioning Segregated Fund, net				9,675
Equity securities	159	-	-	159
Other financial assets	73	-	97	170
Liabilities				
Other financial liabilities	(41)	-	-	(41)

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the interim consolidated balance sheets.

During the six months ended June 30, 2025, there were no transfers between Level 1 and Level 2 and into or out of Level 3.

The changes in the net assets measured at fair value that are classified as Level 3 financial instruments for the six months ended June 30, 2025 were as follows:

(millions of dollars)	**Other financial instruments**
Opening balance, January 1, 2025	**97**
Realized losses included in revenue	**(1)**
Unrealized losses included in revenue	**(5)**
Purchases	**7**
Closing balance, June 30, 2025	**98**

Investments Measured at Net Asset Value

Nuclear Segregated Funds

Nuclear Segregated Funds' investments classified as Level 3 consist of real estate, infrastructure, other real assets and private debt investments. The fair value of these investments is determined using financial information as provided by the general partners of the limited partnership funds in which the Nuclear Segregated Funds are invested. Direct investments are valued using appropriate valuation techniques, such as recent arm's-length market transactions, references to current fair values of other instruments that are substantially the same, discounted cash flow analyses, third-party independent appraisals, valuation multiples, or other valuation methods. Any control, size, liquidity or other discount premiums on the investments are considered in the determination of fair value.

The process of valuing investments for which no published market price exists is based on inherent uncertainties and the resulting values may differ from values that would have been used had a ready market existed for these investments. The values may also differ from the prices at which the investments may be sold.

The classes of investments within the Nuclear Segregated Funds that are reported on the basis of Net Asset Value (NAV) as at June 30, 2025 were as follows:

(millions of dollars except where noted)	**Fair Value**	**Unfunded Commitments**	**Redemption Frequency**	**Redemption Notice**
Real Assets				
Infrastructure	**4,751**	**1,579**	**n/a**	**n/a**
Real Estate	**3,295**	**1,180**	**n/a**	**n/a**
Private Debt	**257**	**699**	**n/a**	**n/a**
Other	**434**	**16**	**n/a**	**n/a**
Pooled Funds				
Fixed Income	**2,394**	**n/a**	**Daily**	**1-5 days**
Equity	**1,031**	**n/a**	**Daily**	**1-5 days**
Total	**12,162**	**3,474**		

The fair value of the pooled funds is classified as Level 2. Infrastructure, real estate, other real assets, private debt and other investments are measured using NAV as a practical expedient for determining their fair value.

11. COMMITMENTS AND CONTINGENCIES

Litigation

Various legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of business activities. Each of these matters are subject to various uncertainties. Some of these matters may be resolved unfavourably. While it is not possible to determine the ultimate outcome of the various pending actions, it is the Company's belief that their resolution is not likely to have a material adverse impact on its interim consolidated financial position.

Guarantees

As at June 30, 2025, the total amount of guarantees provided by OPG was nil (December 31, 2024 - $30 million).

Contractual Obligations

OPG's contractual obligations as at June 30, 2025 were as follows:

(millions of dollars)	**2025** [1]	**2026**	**2027**	**2028**	**2029**	**Thereafter**	**Total**
Fuel supply agreements	46	211	207	144	136	321	1,065
Contributions to the OPG registered pension plan [2]	60	128	-	-	-	-	188
Long-term debt repayment	524	674	530	255	505	10,006	12,494
Interest on long-term debt	238	464	453	433	423	5,842	7,853
Short-term debt repayment	900	-	-	-	-	-	900
Commitments related to Darlington Refurbishment project [3]	154	-	-	-	-	-	154
Commitments related to Atura Power development projects [3]	248	113	10	9	-	-	380
Commitments related to Pickering Refurbishment project [3]	428	-	-	-	-	-	428
Commitments related to Darlington New Nuclear Project [3]	235	-	-	-	-	-	235
Operating licences	30	61	63	61	62	179	456
Operating lease obligations	13	14	12	4	3	36	82
Accounts payable, accrued charges and other payables	1,732	9	10	9	10	284	2,054
Other	51	85	49	35	21	89	330
Total	4,659	1,759	1,334	950	1,160	16,757	26,619

[1] Represents amounts for the remainder of the year.

[2] Represents the estimated pension contributions consistent with the period covered by the actuarial valuation of the OPG registered pension plan as at January 1, 2024. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2027. Funding requirements after January 1, 2027 are excluded due to significant variability in the assumptions required to project the timing of future cash flows.

[3] Represents estimated currently committed costs to close the projects, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Contractual and commercial commitments as noted exclude certain purchase orders, as they represent purchase authorizations rather than legally binding contracts, and are subject to change without significant penalties.

12. BUSINESS SEGMENTS

For a detailed description of each reportable business segment, measure of profit and loss and the Company's Chief Operating Decision Maker, refer to OPG's annual consolidated financial statements as at and for the year ended December 31, 2024.

Segment Income (Loss) For the Three Months Ended June 30, 2025 *(millions of dollars)*	Regulated			Unregulated				
	Nuclear Generation	Nuclear Sustainability Services	Hydroelectric Generation	Contracted Hydroelectric and Other Generation	Atura Power	Other	Elimination	Total
Revenue	1,129	-	431	243	194	1	-	1,998
Leasing revenue	7	-	-	-	-	2	-	9
Other revenue	(1)	35	-	2	-	50	(61)	25
Total revenue	1,135	35	431	245	194	53	(61)	2,032
Fuel expense	79	-	91	32	82	-	-	284
Gross margin	1,056	35	340	213	112	53	(61)	1,748
Operations, maintenance and administration expenses	443	35	109	75	30	29	(61)	660
Depreciation and amortization expenses	196	-	66	42	32	19	-	355
Accretion on fixed asset removal and nuclear waste management liabilities	-	308	-	3	-	-	-	311
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(280)	-	-	-	-	-	(280)
Property taxes	6	-	-	5	1	-	-	12
Other losses (gains)	4	-	8	(19)	1	(3)	-	(9)
Income (loss) before interest and income taxes	407	(28)	157	107	48	8	-	699
Net interest expense								52
Income before income taxes								647
Income tax expense								100
Net income								547

Segment Income (Loss) For the Three Months Ended June 30, 2024 *(millions of dollars)*	Regulated			Unregulated				
	Nuclear Generation	Nuclear Sustainability Services	Hydroelectric Generation	Contracted Hydroelectric and Other Generation	Atura Power	Other	Elimination	Total
Revenue	873	-	403	211	172	-	-	1,659
Leasing revenue	7	-	-	-	-	2	-	9
Other revenue	-	44	-	1	-	45	(67)	23
Total revenue	880	44	403	212	172	47	(67)	1,691
Fuel expense	79	-	88	13	60	-	-	240
Gross margin	801	44	315	199	112	47	(67)	1,451
Operations, maintenance and administration expenses	619	44	103	79	30	32	(67)	840
Depreciation and amortization expenses	157	-	47	50	30	20	-	304
Accretion on fixed asset removal and nuclear waste management liabilities	-	302	-	2	-	1	-	305
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(274)	-	-	-	-	-	(274)
Property taxes	7	-	1	4	-	-	-	12
Other losses (gains)	4	-	5	(1)	-	13	-	21
Income (loss) before interest and income taxes	14	(28)	159	65	52	(19)	-	243
Net interest expense								51
Income before income taxes								192
Income tax expense								26
Net income								166

Segment Income (Loss)	**Regulated**			**Unregulated**				
For the Six Months Ended June 30, 2025 *(millions of dollars)*	**Nuclear Generation**	**Nuclear Sustainability Services**	**Hydroelectric Generation**	**Contracted Hydroelectric Other Generation**	**Atura Power**	**Other**	**Elimination**	**Total**
Revenue	**2,261**	**-**	**839**	**474**	**538**	**13**	**-**	**4,125**
Leasing revenue	**14**	**-**	**-**	**-**	**-**	**3**	**-**	**17**
Other revenue	**(1)**	**71**	**-**	**1**	**-**	**98**	**(122)**	**47**
Total revenue	**2,274**	**71**	**839**	**475**	**538**	**114**	**(122)**	**4,189**
Fuel expense	**161**	**-**	**163**	**55**	**277**	**-**	**-**	**656**
Gross margin	**2,113**	**71**	**676**	**420**	**261**	**114**	**(122)**	**3,533**
Operations, maintenance and administration expenses	**948**	**71**	**210**	**153**	**53**	**58**	**(122)**	**1,371**
Depreciation and amortization expenses	**390**	**-**	**132**	**83**	**65**	**40**	**-**	**710**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**618**	**-**	**5**	**1**	**-**	**-**	**624**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(564)**	**-**	**-**	**-**	**-**	**-**	**(564)**
Property taxes	**13**	**-**	**-**	**10**	**1**	**1**	**-**	**25**
Other losses (gains)	**7**	**-**	**8**	**(19)**	**1**	**(22)**	**-**	**(25)**
Income (loss) before interest and income taxes	**755**	**(54)**	**326**	**188**	**140**	**37**	**-**	**1,392**
Net interest expense								**108**
Income before income taxes								**1,284**
Income tax expense								**228**
Net income								**1,056**

Segment Income (Loss) **For the Six Months Ended** **June 30, 2024** *(millions of dollars)*	**Regulated**		**Unregulated**					
	Nuclear Generation	**Nuclear Sustainability Services**	**Hydroelectric Generation**	**Contracted Hydroelectric and Other Generation**	**Atura Power**	**Other**	**Elimination**	**Total**
Revenue	1,766	-	787	415	407	9	-	3,384
Leasing revenue	14	-	-	-	-	3	-	17
Other revenue	-	80	-	7	-	96	(126)	57
Total revenue	1,780	80	787	422	407	108	(126)	3,458
Fuel expense	144	-	158	26	165	-	-	493
Gross margin	1,636	80	629	396	242	108	(126)	2,965
Operations, maintenance and administration expenses	1,292	80	204	151	50	59	(126)	1,710
Depreciation and amortization expenses	318	-	93	93	60	40	-	604
Accretion on fixed asset removal and nuclear waste management liabilities	-	605	-	4	1	1	-	611
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(545)	-	-	-	-	-	(545)
Property taxes	13	-	1	9	1	-	-	24
Other losses (gains)	4	-	5	(4)	-	13	-	18
Income (loss) before interest and income taxes	9	(60)	326	143	130	(5)	-	543
Net interest expense								96
Income before income taxes								447
Income tax expense								56
Net income								391

Selected Interim Consolidated Balance Sheets information as at June 30, 2025 *(millions of dollars)*	Regulated		Unregulated				
	Nuclear Generation	Nuclear Sustainability Services	Hydroelectric Generation	Contracted Hydroelectric and Other Generation	Atura Power	Other	Total
Segment property, plant and equipment in-service, net	14,019	-	8,201	6,176	2,973	260	31,629
Segment construction in progress	4,629	-	582	146	981	343	6,681
Segment property, plant and equipment, net	18,648	-	8,783	6,322	3,954	603	38,310
Segment intangible assets in-service, net	48	-	2	234	92	147	523
Segment development in progress	22	-	-	1	-	19	42
Segment intangible assets, net	70	-	2	235	92	166	565
Segment goodwill	-	-	-	218	-	-	218
Segment fuel inventory	341	-	-	28	33	-	402
Segment materials and supplies inventory							
Current	178	-	-	3	-	-	181
Long-term	327	-	-	1	-	-	328
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	-	22,864	-	-	-	-	22,864
Loan receivable	-	-	-	-	-	901	901
Fixed asset removal and nuclear waste management liabilities	-	(26,087)	-	(158)	(55)	(52)	(26,352)

Selected Consolidated Balance Sheets information as at December 31, 2024 *(millions of dollars)*	**Nuclear Generation**	**Regulated Nuclear Sustainability Services**	**Hydroelectric Generation**	**Unregulated Contracted Hydroelectric and Other Generation**	**Unregulated Atura Power**	**Unregulated Other**	**Total**
Segment property, plant and equipment in-service, net	14,046	-	8,189	6,322	3,033	224	31,814
Segment construction in progress	3,139	-	398	140	426	214	4,317
Segment property, plant and equipment, net	17,185	-	8,587	6,462	3,459	438	36,131
Segment intangible assets in-service, net	48	-	2	244	95	145	534
Segment development in progress	18	-	-	1	-	37	56
Segment intangible assets, net	66	-	2	245	95	182	590
Segment goodwill	-	-	-	230	-	-	230
Segment fuel inventory	231	-	-	39	27	-	297
Segment materials and supplies inventory							
Current	142	-	-	3	-	-	145
Long-term	352	-	-	3	-	-	355
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	-	22,412	-	-	-	-	22,412
Loan receivable	-	-	-	-	-	902	902
Fixed asset removal and nuclear waste management liabilities	-	(25,773)	-	(161)	(54)	(54)	(26,042)

Segment Capital Expenditure	Regulated		Unregulated				
(millions of dollars)	**Nuclear Generation**	**Nuclear Sustainability Services**	**Hydroelectric Generation**	**Contracted Hydroelectric and Other Generation**	**Atura Power**	**Other**	**Total**
Three months ended June 30, 2025							
Investment in property, plant and equipment and intangible assets	**818**	**-**	**167**	**35**	**390**	**90**	**1,500**
Net change in accruals and other non-cash items							**34**
Investment in property, plant and equipment and intangible assets – cash flow							**1,534**
Three months ended June 30, 2024							
Investment in property, plant and equipment and intangible assets	703	-	86	45	126	33	993
Net change in accruals and other non-cash items							57
Investment in property, plant and equipment and intangible assets – cash flow							1,050

Segment Capital Expenditure	Regulated		Unregulated				
(millions of dollars)	**Nuclear Generation**	**Nuclear Sustainability Services**	**Hydroelectric Generation**	**Contracted Hydroelectric and Other Generation**	**Atura Power**	**Other**	**Total**
Six months ended June 30, 2025							
Investment in property, plant and equipment and intangible assets	**1,758**	**-**	**291**	**69**	**557**	**167**	**2,842**
Net change in accruals and other non-cash items							**(226)**
Investment in property, plant and equipment and intangible assets – cash flow							**2,616**
Six months ended June 30, 2024							
Investment in property, plant and equipment and intangible assets	1,204	-	159	98	200	58	1,719
Net change in accruals and other non-cash items							11
Investment in property, plant and equipment and intangible assets – cash flow							1,730

13. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

	Six Months Ended June 30	
(millions of dollars)	**2025**	**2024**
Receivables from related parties	**34**	98
Fuel inventory	**(99)**	(33)
Materials and supplies	**(36)**	(3)
Prepaid expenses	**13**	(18)
Other current assets	**51**	10
Accounts payable, accrued charges and other payables	**170**	(69)
Net changes in non-cash working capital balances	**133**	(15)

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May 13, 2025

OPG reports 2025 first quarter financial results

Secures Darlington SMR construction approval; explores Indigenous community-led Northern Ontario hydro opportunities; completes $1 billion green bond issuance

Toronto – Ontario Power Generation Inc. (OPG or Company) today reported its financial and operating results for the first quarter of 2025, with net income attributable to the Shareholder of $505 million, compared to $221 million for the same period last year.

Darlington New Nuclear Project Licence to Construct Approval

With the recent approval of the Darlington New Nuclear Project (DNNP) Licence to Construct by the Canadian Nuclear Safety Commission for one small modular reactor (SMR), OPG will now start the execution phase of Canada's first grid-scale SMR using the BWRX-300 technology, expecting to complete the construction by the end of the decade and connect the facility to the electricity grid by the end of 2030.

"Our success to date in delivering on the $12.8 billion Darlington Refurbishment Project has paved the way for new opportunities, including the DNNP," said Nicolle Butcher, OPG President and CEO. "A first for North America, this made-in-Ontario project showcases our domestic expertise to the world, and will drive economic growth while helping meet increasing energy demand."

As the first mover on SMRs, this project will create jobs for Ontario workers and contracts for Ontario's supply chains and will demonstrate their capabilities to the world while strengthening Canada's energy security. Over 80 per cent of the DNNP will be procured domestically, with a further 15 per cent sourced through Europe and Japan.

The total cost of the four-unit DNNP, including interest, cost escalation, and contingency, is currently estimated at approximately $20.9 billion. The first unit SMR is expected to cost $6.1 billion, along with systems and services that would be common to all four SMRs planned as part of the project of $1.6 billion. The total budget of $7.7 billion represents the release-quality estimate for both the first SMR and shared infrastructure. OPG and its project partners will continue to refine the total estimated project cost during the definition phase of the remaining three units, incorporating lessons learned from the construction of the first SMR and the Darlington Refurbishment Project.

As a rate regulated project, the recovery of the costs of the DNNP will be reviewed by the Ontario Energy Board in a future proceeding for OPG's regulated prices. The Province has also indicated that it is exploring potential financial policy tools that would benefit ratepayers. In parallel, OPG continues to explore optimal financing arrangements in support of funding requirements for the planned capital investments.

Greenfield Hydroelectric Development

OPG recently signed letters of intent with Taykwa Tagamou Nation (TTN) and Moose Cree First Nation (MCFN) to work together on preliminary planning activities to inform an Indigenous community-led decision-making process on new hydroelectric development in the Moose River Basin.

This includes the proposed Nine Mile Rapids hydroelectric generating station and the Grand Rapids hydroelectric generating station, which would have a combined generating capacity of up to 430 megawatts (MW).

"We look forward to working in meaningful partnership with TTN and MCFN toward the next generation of hydroelectric in Northern Ontario," said Butcher. "These potential new waterpower projects would provide decades of affordable, reliable, domestically produced electricity to meet growing demand and deliver lasting economic benefits to local and Indigenous communities."

Green Bond Issuance

OPG issued $1 billion in green bonds in the first quarter, furthering its leadership in sustainable financing. In all, since 2018, OPG has issued green bonds totalling approximately $5.6 billion, including offerings by its subsidiaries.

Cedar Leaf Capital, Inc. (Cedar Leaf), Canada's first majority Indigenous-owned investment dealer, joined OPG's syndicate of dealers and served as co-manager on the most recent issuance.

"OPG remains the largest Canadian corporate issuer of green bonds and will use proceeds of this issuance to fund a range of low-carbon energy projects," said Butcher. "The opportunity to work with Cedar Leaf is in keeping with our Reconciliation Action Plan commitment to partner with Indigenous communities and businesses to advance meaningful and tangible economic reconciliation."

Strong Canadian Supply Chain

With more than 90 per cent of its goods and services procured from Canadian suppliers for OPG's nuclear and Ontario hydroelectric business, OPG is a major contributor to Ontario's supply chain and economy. OPG continues to strengthen local procurements and identify alternate supplier relationships to mitigate the supply chain risks and broader potential economic impacts associated with changing trade conditions.

First quarter highlights include:

Net income attributable to the Shareholder

Net income attributable to the Shareholder increased by $284 million for the first quarter of 2025, compared to the same period in 2024. The increase was primarily attributable to higher earnings from the Regulated – Nuclear Generation business segment as a result of higher electricity generation, and lower operating, maintenance and administration expenses due to fewer planned cyclical outage activities.

Generating and Operating Performance

Electricity generated in the first quarter of 2025 was 23.5 terawatt hours (TWh), compared to 21.1 TWh for the same period in 2024.

Regulated – Nuclear Generation Segment

Electricity generation from the Regulated – Nuclear Generation business segment increased by 1.9 TWh during the first quarter of 2025 compared to the same quarter in 2024, primarily due to electricity generation from Unit 1 of the Darlington nuclear generating station (Darlington GS) following its return to service from refurbishment in November 2024 and fewer outage days at the Darlington GS and Pickering nuclear generating station (Pickering GS), partially offset by the cessation of commercial operation of Unit 1 and Unit 4 of the Pickering GS in the fourth quarter of 2024.

The unit capability factor at the Darlington GS and Pickering GS increased to 98.5 per cent and 96.6 per cent, respectively, for the first quarter of 2025, compared to 68.1 per cent and 80.3 per cent for the same quarter in 2024, due to fewer planned and unplanned outage days at each station.

Regulated – Hydroelectric Generation Segment

Electricity generation from the Regulated – Hydroelectric Generation business segment for the first quarter of 2025 was comparable to the same quarter in 2024.

Availability at the regulated hydroelectric stations decreased to 85.7 per cent for the first quarter of 2025, compared to 87.9 per cent for the same quarter in 2024. The decrease was primarily due to higher unplanned outages across the regulated hydroelectric fleet in Ontario.

Contracted Hydroelectric and Other Generation Segment

Electricity generation from the Contracted Hydroelectric and Other Generation business segment decreased by 0.2 TWh in the first quarter of 2025, compared to the same quarter in 2024, primarily due to lower water flows across the hydroelectric facilities in the United States.

Availability of the hydroelectric stations in the business segment increased to 88.1 per cent for the first quarter of 2025, compared to 84.0 per cent for the same quarter in 2024, primarily due to fewer planned outages at the Lower Mattagami hydroelectric generating stations in Ontario.

Atura Power Segment

Electricity generation from the Atura Power business segment increased by 0.7 TWh during the first quarter of 2025, compared to the same quarter in 2024, primarily due to higher demand for electricity generation from the combined cycle plants.

Thermal Availability of the generating stations in the segment decreased to 87.3 per cent as at March 31, 2025, compared to 89.6 per cent for the same quarter in 2024, primarily due to a planned outage at the Halton Hills generating station.

Generation Development

The company is undertaking a number of generation development and other projects to maximize the value of and expand its generating fleet in support of Ontario's electricity system.

Darlington Refurbishment

The Darlington Refurbishment Project will extend the operating life of the four-unit Darlington GS by at least 30 years.

The Unit 4 refurbishment is currently in the third major segment, Reassembly, which includes installation and reassembly of reactor components, and continues to progress on schedule. Unit 4 is the last Darlington GS unit to undergo refurbishment and is scheduled to be returned to service in 2026.

The total project costs, including the impacts of the COVID-19 pandemic and inflation, are on track to meet the $12.8 billion budget.

Further details on OPG's major projects can be found in Management's Discussion and Analysis as at and for the three months ended March 31, 2025, section, *Core Business and Outlook* under the heading, *Project Excellence*.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(millions of dollars – except where noted)	Three Months Ended March 31 2025	2024
Revenue	2,157	1,767
Fuel expense	372	253
Operations, maintenance and administration expenses	711	870
Depreciation and amortization expenses	355	300
Accretion on fixed asset removal and nuclear waste management liabilities	313	306
Earnings on nuclear fixed asset removal and nuclear waste management funds	(284)	(271)
Other net (gains) expenses	(3)	9
Earnings before interest and income taxes	693	300
Net interest expense	56	45
Income tax expense	128	30
Net Income	509	225
Net income attributable to the Shareholder	505	221
Net income attributable to non-controlling interest [1]	4	4
Earnings (loss) before interest and income taxes		
Electricity generating business segments	690	318
Regulated – Nuclear Sustainability Services	(26)	(32)
Other	29	14
Earnings before interest and income taxes	693	300
Cash flow provided by operating activities	754	564
Capital expenditures [2]	1,342	726
Electricity generation (TWh)		
Regulated – Nuclear Generation	9.9	8.0
Regulated – Hydroelectric Generation	8.5	8.5
Contracted Hydroelectric and Other Generation [3]	1.2	1.4
Atura Power	3.9	3.2
Total OPG electricity generation	23.5	21.1
Nuclear unit capability factor (per cent)		
Darlington Nuclear GS [4]	98.5	68.1
Pickering Nuclear GS	96.6	80.3
Availability (per cent)		
Regulated – Hydroelectric Generation	85.7	87.9
Contracted Hydroelectric and Other Generation – hydroelectric stations	88.1	84.0
Atura Power [5]	87.3	89.6

[1] Relates to the following: 25 per cent interest of Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in Lower Mattagami Limited Partnership; 33 per cent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in PSS Generating Station Limited Partnership; 15 per cent and 5 per cent interests of corporations wholly owned by Six Nations of Grand River Development Corporation and the Mississaugas of the Credit First Nation, respectively, in Nanticoke Solar LP; and non-controlling interests in certain electricity generating facilities in the United States.

[2] Includes net changes in accruals.

[3] Includes OPG's proportionate share of electricity generation from co-owned and minority shareholdings in electricity generating facilities.

[4] Excludes nuclear unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 1 of the Darlington GS was excluded from the reported planned and unplanned outage days during its refurbishment period of February 15, 2022 to November 27, 2024 and Unit 4 of the Darlington GS has been excluded from the measure since commencing refurbishment on July 19, 2023.

[5] Reflects the thermal availability of combined cycle plants as at the period end date, calculated on a three-year rolling average basis.

About OPG

As one of North America's largest, most diverse electricity generators, OPG invests in local economies and employs thousands of people across Ontario. OPG and its family of companies are advancing the development of new low-carbon technologies, refurbishment projects, and electrification initiatives to power the growing demands of a clean economy.

Ontario Power Generation Inc.'s unaudited interim consolidated financial statements and Management's Discussion and Analysis as at and for the three months ended March 31, 2025, can be accessed on OPG's web site (www.opg.com), the Canadian Securities Administrators' web site (www.sedarplus.com), or can be requested from the Company.

For further information, please contact:

Ontario Power Generation
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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2025 FIRST QUARTER REPORT

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ONTARIO POWER GENERATION

ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. and its subsidiaries (OPG or Company) as at and for the three months ended March 31, 2025. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars, unless otherwise noted.

For a complete description of OPG's corporate strategies, risk management, corporate governance, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, Annual Information Form, and MD&A as at and for the year ended December 31, 2024.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG has also received exemptive relief from the Ontario Securities Commission (OSC) that allows OPG to apply US GAAP instead of International Financial Reporting Standards (IFRS). In September 2022, the OSC approved an exemption which allows the Company to continue to apply US GAAP up to January 1, 2027. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2027. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP*, in OPG's 2024 annual MD&A. This MD&A is dated May 13, 2025.

Additional information about OPG, including the Company's Annual Information Form, is available on SEDAR+ at www.sedarplus.com and the Company's website at www.opg.com.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "budget", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could" and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks and uncertainties, including those set out in the section, *Risk Management*, and forecasts discussed in the section, *Core Business and Outlook*. All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station (GS) performance, availability and operating lives, fuel costs, surplus baseload generation (SBG), fixed asset removal and nuclear waste management obligations and costs, availability of facilities for the permanent disposal of used nuclear fuel and other nuclear waste, performance and earnings of segregated nuclear and OPG pension funds, refurbishment of existing facilities, development and construction of new facilities, acquisition transactions and other business expansion opportunities, performance of acquired businesses, divestiture transactions, defined benefit pension and other post-employment benefit (OPEB) obligations and costs, income taxes, proposed new legislation, government policy including tariffs and the trade environment, the ongoing evolution and growth of electricity industries and markets in Ontario, Canada and the United States of America (United States or US), the continued application and renewal of energy supply agreements (ESAs) with the Independent Electricity System Operator (IESO) and other contracts for non-regulated facilities, inflation, interest rates, foreign currency exchange rates, commodity prices, wholesale electricity market prices, environmental and other regulatory requirements, operating licence applications to the Canadian Nuclear Safety Commission (CNSC) and the Federal Energy Regulatory Commission (FERC), health, safety and environmental developments, changes in the Company's workforce, renewal of union collective agreements, business continuity events, the weather, climate change, technological change, geopolitical events, financing requirements and liquidity, funding sources, applications to the Ontario Energy Board (OEB) for regulated prices, the impact of regulatory decisions by the OEB, clean energy investment government programs, forecasts of earnings, cash flow, earnings before interest, income taxes, depreciation and amortization, gross margin, operations, maintenance and administration (OM&A) expenses and project and other expenditures, retention of critical talent, supply chain availability and capacity, and supplier and third party performance. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events or otherwise.

Use of Non-GAAP Financial Measures

The Company uses the following non-GAAP financial performance measures in the MD&A:

- "Earnings before Interest, Income Taxes, Depreciation and Amortization"; and
- "Gross Margin".

For a detailed description of each of the non-GAAP measures used in this MD&A, refer to the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*. The non-GAAP financial performance measures set out in this MD&A are intended to provide additional information to investors and do not have any standardized meaning under US GAAP, and therefore may not be comparable to other issuers, and should not be considered in isolation or as a substitute for measures of performance prepared under US GAAP.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at March 31, 2025, OPG owned and operated two nuclear generating stations, 66 hydroelectric generating stations, two thermal generating stations, one solar facility and four combined-cycle gas turbine (combined cycle) plants in Ontario, Canada. The combined cycle plants are natural gas-fired facilities owned and operated through the Company's wholly-owned subsidiary operating as Atura Power. Through its US-based wholly-owned subsidiary, OPG Eagle Creek Holdings LLC (Eagle Creek), OPG also wholly or jointly owned and operated 85 hydroelectric generating stations and held minority interests in 14 hydroelectric and two solar facilities in the US as at March 31, 2025. In addition, OPG owned two nuclear generating stations in Ontario, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to, and operated by, Bruce Power L.P. (Bruce Power).

Reporting Structure

The composition of OPG's reportable business segments effective as at March 31, 2025 was as follows:

- Regulated – Nuclear Generation;
- Regulated – Nuclear Sustainability Services;
- Regulated – Hydroelectric Generation;
- Contracted Hydroelectric and Other Generation; and
- Atura Power.

Income from the generating stations leased to Bruce Power is included in revenue under the Regulated – Nuclear Generation business segment. The leased stations are not included in the Company's electricity generation and other operating statistics set out in this MD&A.

Trends

OPG's quarterly electricity generation and the financial results of the Regulated – Nuclear Generation business segment are primarily impacted by maintenance outage cycles, unplanned outage activities and timing of refurbishment activities at the nuclear generating stations, which may result in period-over-period variability in OPG's financial results. The maintenance outage cycle at each of OPG's nuclear generating stations determines the number of planned outages in a particular year. Outage cycles are designed to ensure continued safe and reliable long-term operations of the stations and their compliance with the CNSC's regulatory requirements.

The Darlington and Pickering nuclear generating stations have been designed to operate at full power as baseload generating facilities and therefore their electricity production does not vary with changes in grid-supplied electricity demand.

OPG's quarterly electricity generation from the Regulated – Hydroelectric Generation, Contracted Hydroelectric and Other Generation, and Atura Power business segments is affected by changes in grid-supplied electricity demand. Changes in grid-supplied electricity demand are primarily caused by variations in seasonal weather conditions, changes in economic conditions, the impact of small-scale generation embedded in distribution networks, and the impact of conservation efforts. Historically, there has been greater electricity demand in Ontario during the winter and summer months due to heating and air conditioning demands. The financial impact of forgone hydroelectric electricity generation from the Regulated – Hydroelectric Generation business segment due to SBG conditions is mitigated by a regulatory variance account authorized by the OEB.

OPG's quarterly electricity generation from hydroelectric facilities is impacted by weather conditions that affect water flows. Historically, there have been higher water flows in the second quarter as a result of snow and ice melt entering the river systems. The financial impact of variability in water flows on the Regulated – Hydroelectric Generation business segment is mitigated by regulatory variance accounts authorized by the OEB.

The financial impact of variability in electricity generation from the Contracted Hydroelectric and Other Generation business segment and the Atura Power business segment is mitigated by the terms of the applicable ESAs with the IESO for the contracted generating facilities in Ontario.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as at March 31, 2025 and December 31, 2024 was as follows:

	As At	
(MW)	**March 31 2025**	**December 31 2024**
Regulated – Nuclear Generation [1]	**4,698**	4,698
Regulated – Hydroelectric Generation [4]	**6,566**	6,566
Contracted Hydroelectric and Other Generation [2, 4]	**4,080**	4,080
Atura Power	**2,750**	2,715
Total [3]	**18,094**	18,059

[1] The in-service generating capacity as at March 31, 2025 and December 31, 2024 excludes Unit 4 of the Darlington GS. Unit 4 was taken offline for refurbishment in July 2023 and has a generating capacity of 878 MW. As at March 31, 2025, the Darlington GS had three units in service and the Pickering GS had four units in service.

[2] Includes OPG's proportionate share of in-service generating capacity from co-owned and minority shareholdings in electricity generating facilities.

[3] In-service generating capacity represents the portion of installed capacity (the highest level of MW output which a generating unit can maintain indefinitely under reference conditions, without damage to the unit) that has not been removed from service. The Bruce Power leased stations are excluded from electricity generation and operating statistics set out in this MD&A.

[4] In-service generating capacity is initially based on estimates at the time of asset in-service. The final capacity may differ once required engineering assessments have been completed and verified.

During the three months ended March 31, 2025, the total in-service generating capacity increased by 35 megawatts (MW). The increase was due to the completion of the contractual generating capacity upgrades at the Halton Hills GS reported under the Atura Power business segment, which were previously awarded by the IESO in 2023.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results for the three months ended March 31, 2025, compared to the same period in 2024. A discussion of OPG's performance by business segment can be found in the section, *Discussion of Operating Results by Business Segment*.

(millions of dollars – except where noted)	Three Months Ended March 31 2025	2024
Revenue	**2,157**	1,767
Fuel expense	**372**	253
Operations, maintenance and administration expenses	**711**	870
Depreciation and amortization expenses	**355**	300
Accretion on fixed asset removal and nuclear waste management liabilities	**313**	306
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(284)**	(271)
Other net (gains) expenses	**(3)**	9
Earnings before interest and income taxes	**693**	300
Net interest expense	**56**	45
Income tax expense	**128**	30
Net income	**509**	225
Net income attributable to the Shareholder	**505**	221
Net income attributable to non-controlling interest [1]	**4**	4
Electricity generation (TWh) [2]	**23.5**	21.1
Cash flow provided by operating activities	**754**	564
Capital expenditures [3]	**1,342**	726
Earnings (loss) before interest and income taxes by segment		
Regulated – Nuclear Generation	**348**	(5)
Regulated – Hydroelectric Generation	**169**	167
Contracted Hydroelectric and Other Generation [4]	**81**	78
Atura Power	**92**	78
Total electricity generating business segments	**690**	318
Regulated – Nuclear Sustainability Services	**(26)**	(32)
Other	**29**	14
Earnings before interest and income taxes	**693**	300

[1] Relates to the following: 25 percent interest of Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in Lower Mattagami Limited Partnership; 33 percent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in PSS Generating Station Limited Partnership; 15 percent interest and 5 percent interest of corporations wholly owned by Six Nations of Grand River Development Corporation and the Mississaugas of the Credit First Nation, respectively, in Nanticoke Solar LP; and non-controlling interests in certain electricity generating facilities in the United States.

[2] Includes OPG's proportionate share of electricity generation from co-owned and minority-held facilities.

[3] Includes net changes in accruals.

[4] Includes contracted revenue from hydroelectric generating stations in Ontario operating under ESAs, with expiration dates ranging from 2059 to 2067.

Net income attributable to the Shareholder was $505 million for the first quarter of 2025, representing an increase of $284 million compared to the same period in 2024.

Earnings before interest and income taxes (EBIT) were $693 million for the first quarter of 2025, representing an increase of $393 million compared to the same period in 2024.

Significant factors that increased EBIT:

- Increase in revenue of $191 million from the Regulated – Nuclear Generation business segment due to higher electricity generation of 1.9 terawatt hours (TWh). The higher electricity generation was primarily driven by the return to service of Unit 1 of the Darlington nuclear generating station (Darlington GS) following refurbishment in November 2024 and fewer outage days at both the Darlington GS and the Pickering nuclear generating station (Pickering GS); and
- Lower OM&A expenses of $168 million from the Regulated – Nuclear Generation business segment, primarily due to lower expenditures related to the cyclical maintenance activities as a result of fewer planned outage days at the Darlington GS and Pickering GS.

Net interest expense increased by $11 million in the first quarter of 2025, compared to the same period in 2024. The increase was primarily due to higher interest expense on the Company's long-term debt due to bond issuances during 2024 and the first quarter of 2025, partially offset by a higher amount of interest recorded as recoverable from customers through regulatory accounts.

Income tax expense increased by $98 million in the first quarter of 2025, compared to the same period in 2024. The increase was primarily due to the impact of higher earnings before income taxes.

Electricity Generation

Electricity generation for the three months ended March 31 was as follows:

	Three Months Ended March 31	
(TWh)	**2025**	**2024**
Regulated – Nuclear Generation	**9.9**	8.0
Regulated – Hydroelectric Generation	**8.5**	8.5
Contracted Hydroelectric and Other Generation [1]	**1.2**	1.4
Atura Power	**3.9**	3.2
Total OPG electricity generation	**23.5**	21.1

[1] Includes OPG's proportionate share of electricity generation from co-owned and minority shareholdings in electricity generating facilities.

Total OPG electricity generation increased by 2.4 TWh for the three months ended March 31, 2025, compared to the same period in 2024, primarily due to higher electricity generation from the Regulated – Nuclear Generation business segment.

Electricity generation from the Regulated – Nuclear Generation business segment increased by 1.9 TWh for the three months ended March 31, 2025, compared to the same period in 2024. The increase was primarily due to electricity generation from Unit 1 of the Darlington GS following its return to service from refurbishment in November 2024 and fewer outage days at the Darlington and Pickering nuclear generating stations. The increase was partially offset by the cessation of commercial operation of Unit 1 and Unit 4 of the Pickering GS in the fourth quarter of 2024.

Electricity generation from the Contracted Hydroelectric and Other Generation business segment decreased by 0.2 TWh for the three months ended March 31, 2025, compared to the same period in 2024, primarily due to lower water flows across the hydroelectric facilities in the United States.

Electricity generation from the Atura Power business segment increased by 0.7 TWh for the three months ended March 31, 2025, compared to the same period in 2024, primarily due to higher demand for electricity generation from the combined cycle plants.

Ontario's electricity demand as reported by the IESO was 37.7 TWh for the three months ended March 31, 2025, compared to 35.9 TWh for the same period in 2024, excluding electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric and certain nuclear generating stations, and other grid-connected renewable resources. Baseload generation surplus in Ontario was higher in the three months ended March 31, 2025, compared to the same period in 2024. Production forgone at OPG's regulated hydroelectric stations due to SBG conditions was 0.1 TWh for the three months ended March 31, 2025 and nil for the same period in 2024. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear generating stations due to SBG conditions.

Cash Flow from Operations

Cash flow provided by operating activities was $754 million for the three months ended March 31, 2025, compared to $564 million for the same period in 2024. The increase was primarily due to higher revenue receipts from the Regulated – Nuclear Generation business segment, lower income tax installment payments and lower OM&A expenditures.

Capital Expenditures

Capital expenditures were as follows:

(millions of dollars)	Three Months Ended March 31 2025	2024
Regulated – Nuclear Generation – Darlington Refurbishment Project	**229**	231
Regulated – Nuclear Generation – Pickering Refurbishment and DNNP	**605**	131
Regulated – Nuclear Generation – Excluding Darlington Refurbishment Project, Pickering Refurbishment Project and DNNP	**106**	139
Regulated – Hydroelectric Generation	**124**	73
Contracted Hydroelectric and Other Generation	**34**	53
Atura Power	**167**	74
Other	**77**	25
Total capital expenditures [1]	**1,342**	726

[1] Includes net changes in accruals.

Total capital expenditures for the three months ended March 31, 2025 increased by $616 million, compared to the same period in 2024, primarily due to higher expenditures for the Regulated – Nuclear Generation business segment.

Capital expenditures for the Darlington Refurbishment project for the first quarter of 2025 were comparable to the same period in 2024.

Capital expenditures for the Pickering Refurbishment project and the Darlington New Nuclear Project (DNNP) increased by $474 million for the first quarter of 2025, compared to the same period in 2024. The increase was due to higher expenditures on pre-execution refurbishment activities for Units 5 to 8 of the Pickering GS reflecting the project's transition to the definition phase, and higher expenditures for site preparation, procurement and other ongoing development activities for small modular reactors (SMRs) at the DNNP site.

Excluding the Darlington Refurbishment project, Pickering Refurbishment project and DNNP, capital expenditures for the Regulated – Nuclear Generation business segment decreased by $33 million for the first quarter of 2025, compared to the same period in 2024. The decrease was primarily driven by lower expenditures for the replacement of primary moisture separators, a component of steam generators, and other sustaining projects at the Darlington GS.

Capital expenditures for the Regulated – Hydroelectric Generation business segment increased by $51 million for the first quarter of 2025, compared to the same period in 2024. The increase was primarily due to higher expenditures on redevelopments of the Kakabeka Falls, Coniston and Stinson hydroelectric generating stations as well as the ongoing refurbishment program across the hydroelectric fleet.

Capital expenditures for the Contracted Hydroelectric and Other Generation business segment decreased by $19 million for the first quarter of 2025, compared to the same period in 2024. The decrease was primarily due to lower expenditures on the Smoky Falls Dam Safety project, with the two new sluicegates placed in service in the first quarter of 2024.

Capital expenditures for the Atura Power business segment increased by $93 million for the first quarter of 2025, compared to the same period in 2024. The increase was primarily due to higher expenditures for the expansion of the combined cycle plant at the Napanee GS and higher expenditures on the development of a battery energy storage system at the Napanee GS site (Napanee BESS), both under long-term agreements with the IESO.

Capital expenditures within the Other category increased by $52 million for the first quarter of 2025, compared to the same period in 2024. The increase was largely due to higher expenditures related to the retrofitting and renovation of the new corporate headquarters building in Oshawa, Ontario prior to the planned occupancy in summer 2025.

Further details on the Company's major projects can be found in sections, *Core Business and Outlook* under the heading, *Project Excellence,* and *Significant Developments* under the heading, *Project Excellence.*

SIGNIFICANT DEVELOPMENTS

Project Excellence

Darlington New Nuclear Project

OPG continues to advance the DNNP and expects to complete the construction of Canada's first grid-scale SMR by the end of the decade and connect it to the electricity grid by the end of 2030, using the BWRX-300 reactor plant technology.

On April 4, 2025, the CNSC announced its decision to issue a power reactor construction licence to OPG, authorizing the construction of one SMR at the DNNP site. The licence is valid until March 31, 2035 and includes standard licence conditions as well as three Regulatory Hold Points (RHPs) at key project milestones during the licence to construct phase. The removal of the RHPs is tied to completion of design and safety analysis and will allow for the progression of the detailed design and phased construction. Overall, the licence conditions and hold points will enable effective regulatory oversight of the licensed activities.

In May 2025, the Province announced its support of OPG to proceed with the execution phase of the first SMR at the DNNP site. The total cost of the four-unit DNNP, including interest, cost escalation, and contingency, is currently estimated at approximately $20.9 billion. The first unit SMR is expected to cost $6.1 billion along with systems and services that would be common to all four SMRs planned as part of the project of $1.6 billion. The total budget of $7.7 billion represents the release-quality estimate for both the first SMR and shared infrastructure, and was approved by the OPG Board of Directors (Board). OPG and its project partners will continue to refine the total estimated project cost during the definition phase of the remaining three units, incorporating lessons learned from the construction of the first SMR and the Darlington Refurbishment project.

OPG is advancing planning and licensing activities for three additional SMRs at the DNNP site. On March 5, 2025, the Ministry of Environment and Climate Change announced $55 million in funding from the Environment and Climate Change Canada's Future Electricity Fund to support the development of these SMRs. Pending the Province and regulatory approvals for the construction of these additional SMRs, the DNNP's total generating capacity is expected to reach approximately 1,200 MW.

The SMRs at the DNNP site are prescribed for rate regulation by the OEB. As a rate regulated project, the recovery of the costs of the DNNP will be reviewed by the OEB in a future proceeding for OPG's regulated prices. The Province has also indicated that it is exploring potential financial policy tools that would benefit ratepayers. In parallel, OPG continues to explore optimal financing arrangements in support of funding requirements for the planned capital investments.

Pickering Refurbishment Project

In January 2025, the Province announced its approval of OPG's plan to proceed with the project definition phase as the next step toward refurbishing Units 5 to 8 of the Pickering GS. The Board approved budget for this work is $4.1 billion, bringing the total Board-approved budget for the project to date to $6.2 billion. During the definition phase, OPG is expecting to complete a high-quality cost estimate and schedule for the project, progress detailed engineering, further procurement and contracting work, continue to optimize project scope, and develop the project execution plan. The definition phase is expected to last through 2026.

Once refurbished, the Pickering GS would continue to provide over 2,000 MW of baseload generating capacity, equivalent to powering approximately two million homes, to help meet Ontario's demand for electricity. The refurbishment is anticipated to be completed by the mid-2030s.

Further details on the continued operation plan for the Pickering GS can be found in the section, *Core Business and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability*.

Redevelopment of Matabitchuan Hydroelectric Generating Station

In March 2025, OPG initiated the execution phase of a project to redevelop the 114-year-old Matabitchuan hydroelectric generating station (Matabitchuan GS), located along the Matabitchuan River in northeastern Ontario. The redeveloped station is expected to have a generating capacity of approximately 12 MW and will ensure continued safe and reliable operations for approximately an additional 90 years. The project's expected in-service date is in 2028, with an approved budget of $190 million. The Matabitchuan GS is reported in the Regulated – Hydroelectric Generation business segment.

Northern Ontario Hydroelectric Opportunities

In April 2025, the Province announced that it is working in partnership with the Taykwa Tagamou Nation (TTN) and Moose Cree First Nation (MCFN) to explore and advance opportunities for two new hydroelectric generating stations in Northeast Ontario, with combined generating capacity of up to 430 MW. This includes the proposed Nine Mile Rapids hydroelectric generating station on the Abitibi River and the proposed Grand Rapids hydroelectric generating station on the Mattagami River. The TTN and MCFN, having named OPG as the partner-in-principle, have signed letters of intent with OPG and will jointly lead a co-planning process to determine a potential path forward for the development of these potential sites, contingent on community support.

Financial Strength

Green Bonds

On March 13, 2025, OPG issued $1 billion of green bonds under its Sustainable Finance Framework, through its Medium Term Note Program. The issuance consisted of $500 million of senior notes maturing in March 2035, with a coupon interest rate of 4.32 percent, and $500 million of senior notes maturing in March 2055, with a coupon interest rate of 4.87 percent. The net proceeds from the issuance were used to finance or re-finance Eligible Green Projects as defined under the Sustainable Finance Framework.

CORE BUSINESS AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements* at the beginning of the MD&A.

The following sections provide an update to OPG's disclosures in the 2024 annual MD&A related to its four business imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these imperatives as part of OPG's corporate strategy is included in the 2024 annual MD&A in the sections, *The Company* and *Core Business and Outlook*.

Operational Excellence

Electricity Generation Production and Reliability

Nuclear Operations

OPG's plan to optimize the end of operations dates for the Pickering GS includes operating Units 5 to 8 until the end of September 2026, prior to the planned refurbishment. In the first quarter of 2025, OPG submitted a notification letter to the CNSC regarding Pickering site projects, including activities in support of refurbishing Units 5 to 8, to be conducted under the existing CNSC power reactor operating licence for the Pickering GS, which is valid until August 31, 2028. The CNSC's questions on the notification have been addressed and no further action is required. OPG expects to submit an application to the CNSC to renew the operating licence for the Pickering GS in the third quarter of 2025 and will include the planned refurbishment activities.

In May 2024, OPG submitted an application to renew the power reactor operating licence for the Darlington GS, valid until November 30, 2025, for a period of 30 years. The first part of the two-part public hearing on the application was completed in March 2025, with the second part of the hearing scheduled to be held by the CNSC in June 2025.

Renewable Generation Operations

OPG continues to progress on an ongoing refurbishment program for its hydroelectric generating units across Ontario. In April 2025, OPG completed the refurbishment of Unit 2 at the Barrett Chute GS, located on the Madawaska River in eastern Ontario, marking the completion of the refurbishment of all four units at the generating station.

Collective Agreements

Construction work in Ontario is performed through craft unions with established bargaining rights at OPG facilities. These bargaining rights are established either through the Electrical Power Systems Construction Association (EPSCA) or directly with OPG or its wholly-owned subsidiaries. The associated collective agreements are negotiated either directly between the parties or through the EPSCA, as applicable. Most of these collective agreements currently have multi-year terms that expire on April 30, 2025. Negotiations for the renewal of the EPSCA collective agreements are ongoing, with 18 agreements finalized and two agreements pending negotiations. All renewal agreements are expected to have five-year terms covering the period from May 1, 2025 to April 30, 2030. EPSCA is a voluntary association of owners and contractors who perform work in Ontario's electrical power systems sector.

Project Excellence

Darlington Refurbishment

The Darlington GS Unit 4 refurbishment activities are currently in the Reassembly segment and are progressing as planned. As part of the segment, the calandria tube, and upper and middle feeder installation series were completed in the first quarter of 2025. The total project costs, including the impacts of the COVID-19 pandemic, are on track to meet the $12.8 billion budget.

OPG's major projects in the execution phase as at March 31, 2025 are outlined below:

Project	Capital Expenditures		Approved Budget	Expected In-service Date	Current Status
(millions of dollars)	Year-to-date	Life-to-date			
Darlington Refurbishment Project	229	11,419	12,800 [1]	Unit 4 – 2026	The Unit 4 refurbishment is progressing on schedule and is currently in the Reassembly segment. The project is tracking on budget.
Redevelopment of Kakabeka Falls Hydroelectric GS	29	68	519	2028	Remaining design and site preparation activities are progressing on schedule, and the prime contractor was mobilized to the site in March 2025. The removal of original equipment is also underway. The project is tracking on schedule and on budget.
Atura Power Development Projects	128	416	1,500 [2]	Niagara Hydrogen Centre – 2026 Napanee BESS – 2026 Napanee Combined Cycle GS Expansion Project – 2028	The Niagara Hydrogen Centre project has secured the full building permit. The civil construction activities are in the final stages of completion. The Napanee BESS project continues to progress civil and foundation construction work. The delivery of critical equipment has commenced. Engineering, design and permitting activities for the Napanee Combined Cycle GS Expansion project continue to progress on schedule. These projects are tracking within the total approved budget.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS. The refurbishments of Units 1 to 3 have been completed. Refurbishment of the four generating units is expected to extend the operating life of the station by at least 30 years.

[2] The total project budget of approximately $1.5 billion is for the Niagara Hydrogen Centre, the Napanee BESS and the Napanee Combined Cycle GS Expansion projects.

Financial Strength

Increasing Revenue, Reducing Costs and Achieving Appropriate Return

In line with its commercial mandate, OPG is focused on increasing revenue and net income, and achieving an appropriate return on the Shareholder's investment, while seeking to minimize the impact on electricity customers through continuous improvement in the Company's cost structure.

For regulated operations, achievement of the above objectives is largely dependent on outcomes of OPG's applications for regulated prices to the OEB and prudent growth of rate base earning a return. Rate base for OPG represents the average net level of investment in regulated fixed and intangible assets in service and an allowance for working capital.

The following table presents the OEB-authorized regulated prices for electricity generated from OPG's regulated facilities in Ontario for the period from January 1, 2024 to December 31, 2026 in effect as of the date of this MD&A:

($/MWh)	**2024**	**2025**	**2026**
Regulated – Nuclear Generation			
Base regulated price [1]	103.48	**102.85**	111.33
Deferral and variance account rate riders [2]	4.28	**8.76**	12.43
Total regulated price	107.76	**111.61**	123.76
Regulated – Hydroelectric Generation			
Base regulated price	43.88	**43.88**	43.88
Deferral and variance account rate riders [2]	3.64	**3.30**	3.30
Total regulated price	47.52	**47.18**	47.18

[1] Base regulated prices for the nuclear facilities were established using a rate smoothing approach that defers a portion of each year's approved nuclear revenue requirement for future collection in the Rate Smoothing Deferral Account. Base regulated prices for the nuclear facilities do not include amounts deferred in the Rate Smoothing Deferral Account.

[2] Deferral and variance account (regulatory account) riders reflect the OEB's January 2022 payment amounts order that authorized recovery and repayment of balances recorded in regulatory accounts as at December 31, 2019, and, effective July 2024, the OEB's June 2024 decision and order that authorized recovery and repayment of balances recorded in regulatory accounts as at December 31, 2022.

The base regulated prices for OPG's nuclear electricity generation in effect for the period from January 1, 2022 to December 31, 2026 were established by the payment amounts order issued by the OEB in January 2022 reflecting the OEB's decisions on OPG's 2022-2026 rate application issued during the second half of 2021.

Pursuant to *Ontario Regulation 53/05*, the base regulated price for OPG's hydroelectric electricity generation (hydroelectric base regulated price) for the period from January 1, 2022 to December 31, 2026 has been set equal to the 2021 hydroelectric base regulated price.

In 2024, the OEB initiated a generic cost of capital proceeding to review the methodology for determining the cost of capital parameters and deemed capital structure used for setting utility rates. As part of its decision issued in March 2025, the OEB updated the cost of capital parameters including the prescribed rate of return on deemed equity applicable to all electricity transmitters, electricity distributors, natural gas utilities, and rate-regulated electricity generators. As a result, the interim prescribed return on a deemed equity portion (ROE) of 9.25 percent applicable to 2025 cost-based rate applications was updated to 9.0 percent on a final basis, effective January 1, 2025. The prescribed ROE will continue to be updated annually through the OEB's ROE adjustment formula. These changes do not affect the prescribed ROE levels or other cost of capital parameters reflected in OPG's previously authorized regulated prices for the period through December 31, 2026. While the OEB did not make changes to deemed capital structures in this proceeding, it stated that it would consider, on its merits, a proposal by OPG to modify its deemed

capital structure, should OPG submit one in its next application for new regulated prices. For information on OEB-approved cost of capital parameters and rate base levels reflected in OPG's authorized regulated prices through December 31, 2026, refer to OPG's 2024 annual MD&A in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation.*

In January 2025, the Province released a proposal for potential amendments to *Ontario Regulation 53/05* intended to clarify the scope of the Pickering B Extension Variance Account to ensure that OPG can record costs incurred beginning in 2024 to retain the capacity and readiness to operate Units 5 to 8 of the Pickering GS upon refurbishment, subject to the requisite approvals. The comment period for the proposal ended on March 14, 2025.

In April 2025, the Province released a proposal for potential amendments to *Ontario Regulation 53/05* to allow for the creation of a new variance account to record pre-development expenses for proposed hydroelectric projects by OPG. The comment period for the proposal ends on June 13, 2025.

Under the current OEB rate-setting framework, OPG begins recovering costs through regulated prices once projects are placed in-service. In May 2025, the Province proposed potential changes in regulations that would establish a new mechanism for concurrent cost recovery to allow OPG to recover debt interest during the construction period of the DNNP and also the Pickering Refurbishment project (if the project is approved to proceed). The proposed change would also prescribe a new OEB-regulated generator and establish the applicable rate-setting framework to enable OPG to enter into commercial partnerships for the DNNP. The comment period for the proposal ends on June 26, 2025.

For generation assets that do not form part of the rate regulated operations, OPG generally seeks to secure long-term revenue arrangements that support an appropriate return on the investment. In line with this strategy, all of OPG's non-regulated facilities in Ontario are subject to ESAs with the IESO. These contracts are generally designed to provide for recovery of operating costs and capital investment in the underlying facilities and a return on invested capital, subject to the facilities continuing to meet their contractual obligations.

Ensuring Availability of Cost Effective Funding

OPG actively monitors its funding requirements and forecasts availability of funds to ensure that it can meet the Company's operational needs, project and other commitments, and long-term obligations. In addition to funds generated from operations, OPG utilizes the following primary funding sources: commercial paper; letters of credit; credit facilities; public debt offerings; debt sourced from the Ontario Electricity Financial Corporation (OEFC) and Ontario Financing Authority (OFA), agencies of the Province; and private placement and other project financing arrangements.

Credit Ratings

Maintaining an investment grade credit rating supports OPG's ability to access cost effective financing. As at March 31, 2025, the Company's credit ratings were as follows:

Type of Rating	DBRS Limited (DBRS) [1]	S&P Global Ratings (S&P) [2]	Moody's Investors Service (Moody's) [3]
Issuer rating	A (low)	BBB+	A3
Senior unsecured debt	A (low)	BBB+	A3
Trend/Outlook	Stable	Stable	Stable
Commercial paper program – Canada	R-1 (low)	A-1 (low)	NR [4]
Commercial paper program – US	NR [4]	A-2	P-2

[1] In April 2025, DBRS confirmed OPG's A (low) issuer rating, A (low) senior unsecured debt rating and R-1 (low) Canadian commercial paper rating, all with Stable trends.
[2] In August 2024, S&P confirmed OPG's ratings including BBB+ issuer rating with stable outlook, BBB+ senior unsecured debt rating and A-1 (low) Canada commercial paper rating.
[3] In May 2024, Moody's confirmed OPG's A3 issuer rating with stable outlook, A3 senior unsecured debt rating and P-2 US commercial paper rating.
[4] NR indicates no rating assigned.

Additional discussion of the Company's credit facilities and liquidity can be found in the section, *Liquidity and Capital Resources*.

Social Licence

OPG is committed to maintaining high standards of public health and safety and corporate citizenship, including environmental stewardship, transparency, community engagement and Indigenous relations. The Company also strives to be a leader in climate change action, equity, diversity and inclusion (ED&I) practices, and in advancing reconciliation with Indigenous peoples.

Further details on social licence activities and initiatives can be found in the section, *Environmental, Social, Governance and Sustainability*.

Outlook

OPG's net income and capital expenditures outlook for 2025 remains consistent with the outlook provided in the 2024 annual MD&A.

The Company's operating results in 2025 may be impacted by macro-economic factors and geopolitical events, including tariffs and the trade environment, as discussed further in the section, *Risk Management.*

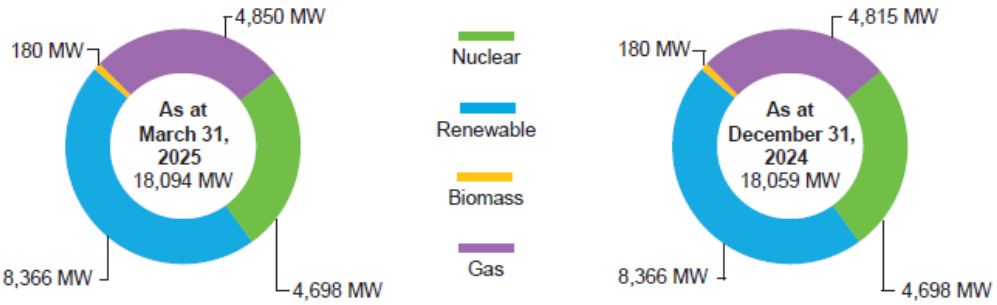
Further details on OPG's outlook, including capital expenditures and financing and liquidity, can be found in OPG's 2024 annual MD&A in the section, *Core Business and Outlook* under the heading, *Outlook*.

ENVIRONMENTAL, SOCIAL, GOVERNANCE AND SUSTAINABILITY

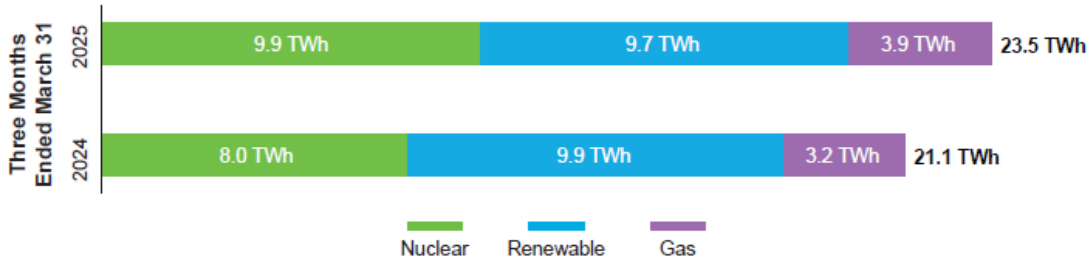
The following sections provide an update to disclosures in the 2024 annual MD&A, related to OPG's social licence activities, sustainability and environmental, social, governance (ESG) and sustainability metrics.

Climate-Related Performance and Key Metrics

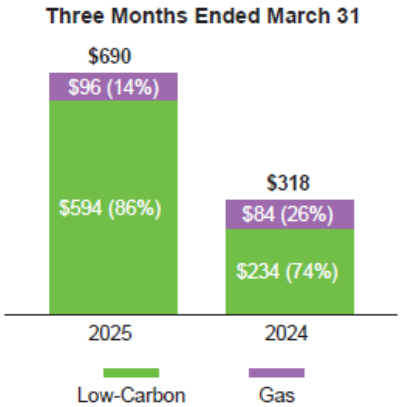
In-service generating capacity by generation type (MW) [1]



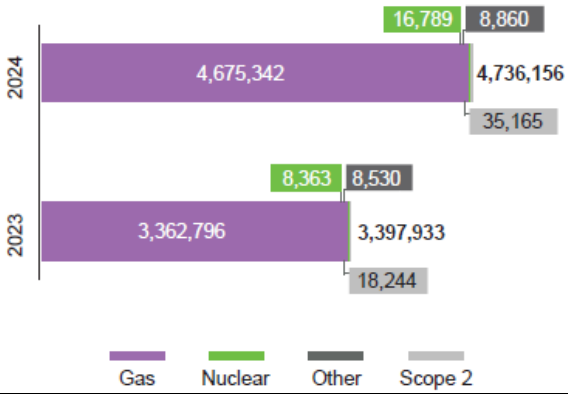
Electricity generation by generation type (TWh) [1, 2]



EBIT from generating stations by facility category (millions of dollars); Climate-related transition risk [1]



Scope 1 and Scope 2 GHG emissions (tonnes CO_2 e) [3]



[1] Includes OPG's proportionate share of in-service generating capacity and electricity generation from co-owned and minority-held facilities. Nuclear generating units undergoing refurbishment are excluded. Gas category includes the dual-fueled Lennox GS and the Company's combined cycle plants operated through Atura Power.

[2] Electricity generated from the Biomass category for the three months ended March 31, 2025 represents 0.03 TWh (March 31, 2024 – 0.04 TWh).

[3] OPG continues to evaluate and enhance its Scope 1 and 2 GHG emission sources and quantification processes.

Climate Change Metrics	
In-service generating capacity by generation type [1]	In-service generating capacity from low-carbon emitting and gas generation sources increased as at March 31, 2025, compared to December 31, 2024, due to the completion of the contractual generating capacity upgrades at the Halton Hills GS. Low-carbon sources continue to account for the majority of OPG's total in-service generating capacity.
Electricity generation by generation type [1]	Low-carbon sources, which comprise nuclear, renewable and biomass generation, accounted for approximately 83 percent of OPG's total electricity generation during the first quarter of 2025, compared to 85 percent during the same period in 2024. The percentage decrease was primarily due to an increase in electricity generation from the Atura Power business segment, due to higher demand for electricity generation from the combined cycle plants.
EBIT from generating stations by facility category; Climate-related transition risk	The portion of EBIT from low-carbon electricity generation increased during the three months ended March 31, 2025, compared to the same period in 2024, primarily due to higher electricity generation and lower OM&A expenses as a result of fewer planned outage days at the Darlington GS and Pickering GS. For further details, refer to the section, *Discussion of Operating Results by Business Segment* under the heading, *Regulated – Nuclear Generation Segment*.
Scope 1 GHG emissions – Direct and Emission Rate [2]	The Scope 1 GHG emissions metric identifies direct CO_2e emissions from OPG's thermal and nuclear operations and other facilities. For the year ended December 31, 2024, 4,675,342 tonnes of CO_2e (2023 – 3,362,796 tonnes of CO_2e) were emitted by thermal operations, representing over 99 percent of OPG's total CO_2e emissions, with the remainder emitted by nuclear operations and other facilities. The increase in CO_2e emissions in 2024 was primarily due to increased electricity generation from Atura Power's combined cycle plants. For the year ended December 31, 2024, OPG emitted CO_2e at an average rate of 57.2 grams per kilowatt-hour (kWh) of its total electricity generation (2023 – 41.7 grams per kWh).
Scope 2 GHG emissions – Indirect [2]	The Scope 2 GHG emissions metric identifies indirect CO_2e emissions from the purchase of energy from utility providers. For the year ended December 31, 2024, an estimated 35,165 tonnes of CO_2e (2023 – 18,244 tonnes of CO_2e) were emitted based on purchases of energy. The increase in CO_2e emissions in 2024 was primarily due to ongoing efforts to improve the GHG emissions inventory for this category as well as overall increased emissions from the electricity system.

[1] Identifies capacity available from OPG's different generation sources and tracks low-carbon energy capacity relative to other sources. Nuclear, Renewable (which includes hydroelectric and solar) and Biomass (which uses wood pellets from sustainably managed forests) generation are considered to be low-carbon emitting generation sources.

[2] Scope 1 GHG emissions, Emission Rate and Scope 2 GHG emissions are reported annually. Scope 1 GHG emissions for OPG's Lennox and Atura Power generating stations are third-party verified annually. The verification for 2024 emissions has not been completed as of the date of this MD&A. The verified 2024 data will be reported in OPG's 2025 annual MD&A.

Health and Safety

OPG continues to maintain a strong focus on the nuclear safety program and to invest in nuclear safety systems. To ensure continued public safety, radiation exposure to members of the public resulting from the operation of OPG's nuclear generating stations is estimated on an annual basis for individuals living or working near the stations. The annual dose to the public resulting from operations of each nuclear facility is expressed in microsieverts (μSv), which is an international unit of radiation dose measurement.

The doses to the public resulting from OPG's nuclear operations were as follows:

Annual public dose	2024		2023	
	μSv	**% of annual legal limit** [1]	**μSv**	**% of annual legal limit** [1]
Darlington GS	**0.9**	**<0.1%**	0.7	<0.1%
Pickering GS	**1.4**	**0.1%**	1.5	0.2%

[1] The annual legal limit is 1,000 μSv for each nuclear generating station.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

(millions of dollars – except where noted)	Three Months Ended March 31 2025	2024
Electricity generation (TWh)	**9.9**	8.0
Revenue	**1,139**	900
Fuel expense	**82**	65
Gross margin	**1,057**	835
Operations, maintenance and administration expenses	**505**	673
Property taxes	**7**	6
Other losses	**3**	-
Earnings before interest, income taxes, depreciation and amortization	**542**	156
Depreciation and amortization expenses	**194**	161
Earnings (loss) before interest and income taxes	**348**	(5)

Earnings before interest and income taxes from the segment increased by $353 million for the three months ended March 31, 2025, compared to the same period in 2024.

The increase in earnings was largely due to higher revenue of $191 million from higher electricity generation of 1.9 TWh.

The increase in earnings was also driven by lower OM&A expenses of $168 million, primarily due to lower expenditures related to the cyclical maintenance activities as a result of fewer planned outage days at the Darlington GS and Pickering GS.

The lower depreciation and amortization expenses of $20 million, excluding amortization expense related to the recovery and repayment of OEB-authorized regulatory account balances, were primarily due to the cessation of commercial operation of Unit 1 and Unit 4 of the Pickering GS in 2024. The decrease was partially offset by higher depreciation expense recognized from placing capital in service, including the return to service of Unit 1 of the Darlington GS following refurbishment in November 2024, and lower amounts of depreciation expense recorded as recoverable from customers through regulatory accounts.

An increase in revenue for the three months ended March 31, 2025 reflecting the impact of the new rate riders for disposition of regulatory accounts under the OEB's June 2024 decision and order on OPG's application for such disposition, effective July 1, 2024, was largely offset by a corresponding increase in the amortization expense of regulatory assets and regulatory liabilities recorded for regulatory account balances.

The planned and unplanned outage days at the Darlington and Pickering nuclear generating stations were as follows:

	Three Months Ended March 31	
	2025	**2024**
Planned Outage Days		
Darlington GS [1]	**1.1**	42.4
Pickering GS	**7.2**	97.9
Unplanned Outage Days		
Darlington GS [1]	**3.2**	16.0
Pickering GS	**5.3**	9.6

[1] The planned and unplanned outage days exclude unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 1 of the Darlington GS was excluded from the reported planned and unplanned outage days during its refurbishment period of February 15, 2022 to November 27, 2024 and Unit 4 of the Darlington GS has been excluded from the measure since commencing refurbishment on July 19, 2023.

The lower planned outage days at the Darlington GS for the three months ended March 31, 2025, compared to the same period in 2024, were driven by the impact of the station's cyclical maintenance outage on the station's Unit 2 during the first quarter of 2024.

The lower planned outage days at the Pickering GS for the three months ended March 31, 2025, compared to the same period in 2024, were driven by the impact of the station's cyclical maintenance schedule and other planned maintenance and repair work executed at the station during the first quarter of 2024.

The lower unplanned outages days at the Darlington GS for the three months ended March 31, 2025, compared to the same period in 2024, were primarily driven by steam generators repair activities on the station's Unit 3 during the first quarter of 2024.

The Unit Capability Factors for the Darlington and Pickering nuclear generating stations were as follows:

	Three Months Ended March 31	
	2025	**2024**
Unit Capability Factor *(%)* [1, 2]		
Darlington GS	**98.5**	68.1
Pickering GS	**96.6**	80.3

[1] Nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment.
[2] Nuclear Unit Capability Factor is defined in the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures.*

The Unit Capability Factor at both the Darlington GS and the Pickering GS increased for the three months ended March 31, 2025, compared to the same period in 2024, due to fewer planned and unplanned outage days at each station, respectively.

Regulated – Nuclear Sustainability Services Segment

(millions of dollars)	Three Months Ended March 31 2025	2024
Revenue	**36**	36
Operations, maintenance and administration expenses	**36**	36
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**310**	303
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(284)**	(271)
Loss before interest and income taxes	**(26)**	(32)

The segment loss before interest and income taxes decreased by $6 million for the three months ended March 31, 2025, compared to the same period in 2024. The decrease was primarily due to higher earnings on the nuclear fixed asset removal and nuclear waste management segregated funds (Nuclear Segregated Funds), largely offset by higher accretion expense on the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities). The higher accretion expense on the Nuclear Liabilities was due to the increase in the present value of the underlying obligation to reflect the passage of time.

The higher earnings from the Nuclear Segregated Funds were primarily due to the growth in the present value of the underlying funding liabilities per the approved Ontario Nuclear Funds Agreement (ONFA) reference plan in effect. As both the Decommissioning Segregated Fund and the Used Fuel Segregated Fund were in an overfunded position during the three months ended March 31, 2025, and during the same period in 2024, they were not impacted by market returns or the rate of return guarantee provided by the Province for a portion of the Used Fuel Segregated Fund. When both funds are in an overfunded position, OPG limits the amount of Nuclear Segregated Funds assets reported on the consolidated balance sheet to the present value of the underlying funding liabilities per the approved ONFA reference plan in effect.

Further details on the accounting for the Nuclear Segregated Funds can be found in OPG's 2024 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds.*

Regulated – Hydroelectric Generation Segment

(millions of dollars – except where noted)	Three Months Ended March 31 2025	2024
Electricity generation (TWh)	**8.5**	8.5
Revenue [1]	**408**	384
Fuel expense	**72**	70
Gross margin	**336**	314
Operations, maintenance and administration expenses	**101**	101
Earnings before interest, income taxes, depreciation and amortization	**235**	213
Depreciation and amortization expenses	**66**	46
Earnings before interest and income taxes	**169**	167

[1] During the three months ended March 31, 2025 and 2024, the Regulated – Hydroelectric Generation business segment revenue included incentive payments of $5 million and $2 million, respectively, related to the OEB-approved hydroelectric incentive mechanism. The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

Earnings before interest and income taxes from the segment for the three months ended March 31, 2025 were comparable to the same period in 2024.

An increase in revenue for the three months ended March 31, 2025 reflecting the impact of the new rate riders for disposition of regulatory accounts under the OEB's June 2024 decision and order on OPG's application for such disposition, effective July 1, 2024, was largely offset by a corresponding increase in the amortization expense of regulatory assets and regulatory liabilities recorded for regulatory account balances.

The Hydroelectric Availability for the generating stations reported in the Regulated – Hydroelectric Generation business segment was as follows:

	Three Months Ended March 31 2025	2024
Hydroelectric Availability *(%)* [1]	**85.7**	87.9

[1] Hydroelectric Availability is defined in the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*.

The Hydroelectric Availability decreased for the three months ended March 31, 2025, compared to the same period in 2024, primarily due to higher unplanned outages across the regulated hydroelectric fleet.

Contracted Hydroelectric and Other Generation Segment

(millions of dollars – except where noted)	Three Months Ended March 31 2025	2024
Electricity generation (TWh)	**1.2**	1.4
Revenue	**230**	210
Fuel expense	**23**	13
Gross margin	**207**	197
Operations, maintenance and administration expenses	**78**	72
Accretion on fixed asset removal liabilities	**2**	2
Property taxes	**5**	5
Other gains	**-**	(3)
Earnings before interest, income taxes, depreciation and amortization	**122**	121
Depreciation and amortization expenses	**41**	43
Earnings before interest and income taxes	**81**	78

Earnings before interest and income taxes from the segment increased by $3 million for the three months ended March 31, 2025, compared to the same period in 2024. The increase was mainly due to higher earnings from the Ontario-based hydroelectric facilities, driven by higher revenue from the Lower Mattagami generating stations.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) within the Contracted Hydroelectric and Other Generation segment were as follows:

	Three Months Ended March 31 2025	2024
Hydroelectric Availability *(%)* [1, 2]	**88.1**	84.0
Thermal EFOR *(%)* [2]	**20.2**	-

[1] Hydroelectric Availability reflects the Company's hydroelectric generating stations in Ontario and the United States.

[2] Hydroelectric Availability and Thermal EFOR are defined in the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*.

The Hydroelectric Availability increased for the three months ended March 31, 2025, compared to the same period in 2024, primarily due to fewer planned outages at the Lower Mattagami hydroelectric generating stations.

The Thermal EFOR increased for the three months ended March 31, 2025, compared to the same period in 2024, due to higher unplanned outages at the Lennox GS.

Atura Power Segment

(millions of dollars - except where noted)	Three Months Ended March 31 2025	2024
Electricity Generation (TWh)	**3.9**	3.2
Revenue	**344**	235
Fuel expense	**195**	105
Gross margin	**149**	130
Operations, maintenance and administration expenses	**23**	20
Accretion on fixed asset removal liabilities	**1**	1
Property taxes	**-**	1
Earnings before interest, income taxes, depreciation and amortization	**125**	108
Depreciation and amortization expenses	**33**	30
Earnings before interest and income taxes	**92**	78

Earnings before interest and income taxes from the segment increased by $14 million for the three months ended March 31, 2025, compared to the same period in 2024. The increase in earnings was primarily due to higher gross margin as a result of higher demand for electricity generation from the combined cycle plants.

The Thermal Availability for the assets within the Atura Power business segment was as follows:

	As at March 31 2025	2024
Thermal Availability *(%)* [1]	**87.3**	89.6

[1] Thermal Availability is defined in the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*. The measure reflects the availability of the combined cycle plants as at the period end date, calculated on a three-year rolling average basis.

The Thermal Availability for the combined cycle plants decreased as at March 31, 2025, compared to March 31, 2024, primarily due to a planned outage at the Halton Hills GS.

LIQUIDITY AND CAPITAL RESOURCES

OPG maintains a range of funding sources to ensure sufficient liquidity and meet financing requirements. These sources are used for multiple purposes including: to invest in plants and technologies, undertake major projects and business acquisitions, fund long-term obligations such as contributions to the pension fund, make payments under the OPEB plans, fund expenditures on Nuclear Liabilities not eligible for reimbursement from the Nuclear Segregated Funds, service and repay long-term debt, and provide general working capital. Highlights of OPG's interim consolidated cash flow position are noted below.

Changes in cash and cash equivalents were as follows:

	Three Months Ended March 31	
(millions of dollars)	**2025**	**2024**
Cash, cash equivalents and restricted cash, beginning of period	**1,363**	1,481
Cash flow provided by operating activities	**754**	564
Cash flow used in investing activities	**(1,071)**	(811)
Cash flow provided by (used in) financing activities	**1,566**	(312)
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**-**	4
Net increase (decrease) in cash, cash equivalents and restricted cash	**1,249**	(555)
Cash and cash equivalents and restricted cash, end of period	**2,612**	926

For a discussion of cash flow provided by operating activities, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Cash flow used in investing activities for the three months ended March 31, 2025 increased by $260 million, compared to the same period in 2024. The increase was due to higher capital expenditures, primarily within the Regulated – Nuclear Generation business segment, partially offset by the acquisition of Lightstar Renewables LLC and Lightstar Operations One LLC in the same period in 2024.

Financing Activities

Cash flow used in financing activities for the three months ended March 31, 2025 increased by $1,878 million, compared to the same period in 2024. The increase was primarily due to the issuance of $1 billion of green bonds and higher net issuance of corporate commercial paper in the first quarter of 2025, and the repayment of long-term debt in the same period in 2024.

Committed credit facilities and maturity dates as at March 31, 2025 were as follows:

(millions of dollars)		**Amount**
Bank facilities:		
Corporate [1, 2, 3]		**1,211**
Corporate [1]	US Dollars	**750**
Lower Mattagami Energy Limited Partnership [4]		**460**
OPG Eagle Creek Holdings LLC and subsidiaries	US Dollars	**20**
Ontario Financing Authority facility [3]		**1,250**
Ontario Electricity Financial Corporation facility [3]		**750**

[1] Certain corporate credit facilities contain a sustainability-linked feature that allows reduced pricing if the Company meets certain sustainability targets.
[2] On April 2, 2025, OPG issued $172 million of senior notes under the corporate credit facility.
[3] Represents amounts available under the facility net of debt issuances.
[4] Letter of credit of $60 million was outstanding under this facility as at March 31, 2025.

Short-term debt, letters of credit and guarantees were as follows:

	As At	
(millions of dollars)	**March 31 2025**	**December 31 2024**
Lower Mattagami Energy Limited Partnership	**200**	215
Corporate commercial paper	**591**	-
Total short-term debt	**791**	215
Letters of credit	**510**	504
Guarantees	**-**	30

As of March 31, 2025, a total of $510 million of letters of credit had been issued. This included $314 million for the supplementary pension plans, $60 million for Lower Mattagami Energy Limited Partnership, $58 million for general corporate purposes, $43 million for Atura Power, $19 million for Eagle Creek and its subsidiaries, $14 million for UMH Energy Partnership, $1 million for PSS Generating Station Limited Partnership and $1 million for PowerON Energy Solutions LP.

On April 23, 2025, OPG issued $217 million of letters of credit for general corporate purposes to support the DNNP.

Long-term debt balances were as follows:

	As At	
(millions of dollars)	**March 31 2025**	**December 31 2024**
Medium Term Notes payable [1]	**6,950**	5,950
Senior notes payable under corporate credit facilities [2]	**2,859**	2,859
Project financing	**2,916**	2,916
Other	**25**	25
Total long-term debt [3]	**12,750**	11,750

[1] On April 8, 2025, $400 million in notes matured under the Company's Medium Term Note Program.
[2] On April 2, 2025, $172 million senior notes were issued under the Company's corporate credit facilities.
[3] Excludes the impact of fair value premium or discount and unamortized bond issuance fees.

BALANCE SHEET HIGHLIGHTS

Highlights of OPG's interim consolidated financial position are noted below:

(millions of dollars)	As at March 31 2025	As at December 2024
Property, Plant and equipment - net The increase was primarily due to capital expenditures during the quarter, partially offset by depreciation expense. Further details on capital expenditures can be found in the section, *Highlights* under the heading, *Capital Expenditures.*	**37,198**	36,131
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)* The increase was primarily due to earnings recognized on the Nuclear Segregated Funds, partially offset by reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities from the Nuclear Segregated Funds.	**22,633**	22,412
Short-term debt The increase was primarily due to higher net issuances of corporate commercial paper, partially offset by net repayment of commercial paper issued by Lower Mattagami Energy Limited Partnership.	**791**	215
Long-term debt *(current and non-current portions)* The increase was due to issuances under the Company's Medium Term Note Program.	**12,701**	11,707
Fixed asset removal and nuclear waste management liabilities The increase was primarily a result of accretion expense, partially offset by expenditures on fixed asset removal and nuclear waste management activities.	**26,202**	26,042

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's consolidated financial statements or are recorded in the Company's consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to OPG's audited consolidated financial statements as at and for the year ended December 31, 2024. OPG's critical accounting policies are consistent with those noted in OPG's 2024 annual MD&A.

RISK MANAGEMENT

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements* at the beginning of the MD&A. The following section provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2024 annual MD&A in the section, *Risk Management*.

Risks to Achieving Operational Excellence

Tariffs and Trade Environment

Given the highly interconnected nature of the Canadian and US economies, trade and other impacts of tariffs between the two countries could disproportionately impact the Canadian economy. These impacts are expected to increase procurement costs of certain materials for OPG's projects and operations, and may result in supply chain disruptions if there are further restrictions placed on international trade. The economic impacts of the trade disputes could also ultimately impact demand for electricity in Ontario. The Company continues to actively identify procurements or supplier relationships that are now subject to tariffs, and pursuing alternate suppliers to reduce exposure to tariffs. Work is also continuing to identify, evaluate, and mitigate the impact of the changing trade and geopolitical landscape.

Risks to Achieving Project Excellence

Small Modular Reactors

Following the CNSC's decision in April 2025 to issue a power reactor construction licence to OPG to construct the first SMR at its DNNP site, the project risk profile has shifted from initial planning to the construction of a first-of-a-kind grid-scale small modular reactor. OPG continues to identify and address key risks to delivering the project on schedule and budget, and with quality.

Risks to Maintaining Financial Strength

Credit

The Company's credit risk exposure is a function of its electricity sales, trading and hedging activities, and treasury activities including investing and commercial transactions with various suppliers of goods and services. OPG's credit risk exposure relating to energy market transactions as at March 31, 2025 was $677 million, including $605 million with the IESO. OPG continues to consider overall credit risk exposure relating to electricity sales to be low, as the majority of sales are through the IESO-administered market in Ontario.

Commodity Markets

Changes in the market prices of fuels used to produce electricity can adversely impact OPG's earnings and cash flow provided by operating activities. To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts. The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of electricity generation and supply mix and, as such, are subject to change as these forecasts are updated.

	2025 [1]	**2026**	**2027**
Estimated fuel requirements hedged *(%)* [2]	100	78	89

[1] Based on actual fuel requirements hedged for the three months ended March 31, 2025 and forecast for the remainder of the year.
[2] Represents the approximate portion of megawatt-hour (MWh) of expected electricity generation (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the price of fuel is fixed, or for which the Company has entered into contractual arrangements to secure the price of fuel or secure the recovery of fuel costs. In the case of regulated and contracted hydroelectric electricity generation in Ontario, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One Limited (Hydro One), the IESO and the OEFC. Transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions were as follows:

	Three Months Ended March 31			
	2025		2024	
(millions of dollars)	**Income**	**Expense**	**Income**	**Expense**
Hydro One				
Electricity sales	**10**	**-**	6	-
Services	**-**	**6**	-	2
Dividends	**1**	**-**	1	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**35**	-	413
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**42**	-	551
Hydroelectric gross revenue charge	**-**	**30**	-	30
OEFC				
Hydroelectric gross revenue charge	**-**	**37**	-	41
Interest expense on long-term notes	**-**	**21**	-	23
Income taxes	**-**	**173**	-	70
Property taxes	**-**	**3**	-	3
IESO				
Electricity related revenue	**2,043**	**-**	1,582	-
Fair Hydro Trust				
Interest income	**8**	**-**	8	-
	2,062	**347**	1,597	1,133

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of any excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at March 31, 2025 and December 31, 2024, the Nuclear Segregated Funds were reported net of amounts due to the Province of $10,313 million and $10,236 million, respectively.

Balances between OPG and its related parties are summarized below:

(millions of dollars)	As at March 31 2025	As at December 31 2024
Receivables from related parties		
Hydro One	**3**	3
IESO – Electricity related receivables	**605**	608
Fair Hydro Trust	**12**	4
OEFC	**7**	-
Province of Ontario	**7**	1
Loan receivable		
Fair Hydro Trust	**901**	902
Equity securities		
Hydro One shares	**167**	159
Accounts payable, accrued charges and other payables		
Hydro One	**1**	3
OEFC	**73**	85
Province of Ontario	**8**	10
IESO − Electricity related payables	**-**	-
Long-term debt (including current portion)		
Notes payable to OEFC	**2,100**	2,100

OPG may hold Province of Ontario bonds and treasury bills in the Nuclear Segregated Funds and the OPG registered pension plan. As at March 31, 2025, the Nuclear Segregated Funds held $1,840 million of Province of Ontario bonds (December 31, 2024 – $1,740 million) and $3 million of Province of Ontario treasury bills (December 31, 2024 – $8 million). As of March 31, 2025, the OPG registered pension plan held $328 million of Province of Ontario bonds (December 31, 2024 − $327 million) and $4 million of Province of Ontario treasury bills (December 31, 2024 – $9 million). These Province of Ontario bonds and treasury bills are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

INTERNAL CONTROL OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for Internal Control over Financial Reporting (ICOFR) and for its Disclosure Controls and Procedures (DC&P). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact on the financial statements.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected financial information for each of the eight most recently completed quarters. This information is derived from OPG's unaudited interim consolidated financial statements and the audited annual consolidated financial statements, and has been prepared in accordance with US GAAP.

(millions of dollars – except where noted) *(unaudited)*	**March 31 2025**	**December 31 2024**	**September 30 2024**	**June 30 2024**
Electricity generation (*TWh*)	**23.5**	20.4	21.7	18.9
Revenue	**2,157**	1,838	1,891	1,691
Net income	**509**	232	383	166
Less: Net income attributable to non-controlling interest	**4**	4	4	6
Net income attributable to the Shareholder	**505**	228	379	160
Earnings per share, attributable to the Shareholder *(dollars)* [1]	**$1.84**	$0.83	$1.38	$0.58

(millions of dollars – except where noted) *(unaudited)*	**March 31 2024**	**December 31 2023**	**September 30 2023**	**June 30 2023**
Electricity generation (*TWh*)	21.1	20.8	20.9	19.5
Revenue	1,767	1,894	1,882	1,828
Net income	225	454	449	423
Less: Net income attributable to non-controlling interest	4	4	5	5
Net income attributable to the Shareholder	221	450	444	418
Earnings per share, attributable to the Shareholder *(dollars)* [1]	$0.80	$1.64	$1.62	$1.52

[1] Earnings per share was calculated using the weighted average number of shares outstanding of 274.6 million for all periods presented. There were no dilutive securities during any of the periods presented.

KEY OPERATING PERFORMANCE INDICATORS AND NON-GAAP FINANCIAL MEASURES

Key Operating Performance Measures

OPG evaluates the performance of its generating stations using a number of key indicators. Key operating performance indicators aligned with corporate business imperatives include measures of production reliability, cost effectiveness, environmental performance and safety performance. Certain of the measures used vary depending on the generating technology.

Nuclear Unit Capability Factor

The nuclear Unit Capability Factor is a key measure of nuclear station performance. It measures the amount of energy that the unit(s) generated over a period of time, adjusted for externally imposed constraints such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation. Capability factors are primarily affected by planned and unplanned outages. An outage day represents a single unit being offline or derated for an amount of time equivalent to one day. By industry definition, capability factors exclude production losses beyond plant management's control, such as grid-related unavailability. The nuclear Unit Capability Factor also excludes unit(s) during the period in which they are undergoing refurbishment.

Hydroelectric Availability

Hydroelectric Availability represents the percentage of time the generating unit is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period, weighted by unit capacity.

Thermal Equivalent Forced Outage Rate

Equivalent forced outage rate is an index of the reliability of a generating unit at OPG's wholly-owned thermal stations. It is measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

Thermal Availability

Thermal Availability represents the percentage of time a generating unit at Atura Power's combined cycle plants is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period, averaged by the number of facilities owned and operated through Atura Power. The measure is calculated on a three-year rolling average basis.

Other Key Indicators

OPG has also identified certain environmental and safety performance measures, which are discussed in the section, *Environmental, Social, Governance and Sustainability*.

Non-GAAP Financial Performance Measures

In addition to net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in this MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance and ensure availability of cost-effective funding.

These non-GAAP financial measures have not been presented as an alternative to net income or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) Earnings before interest, income taxes, depreciation and amortization is defined as net income before net interest expense, income tax expense and depreciation and amortization expenses.

(2) Gross margin is defined as revenue less fuel expense.

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ONTARIO POWER GENERATION INC.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)
MARCH 31, 2025

ONTARIO POWER GENERATION

INTERIM CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

Three Months Ended March 31 *(millions of dollars except where noted)*	**2025**	**2024**
Revenue	**2,157**	1,767
Fuel expense	**372**	253
Gross margin	**1,785**	1,514
Operations, maintenance and administration expenses	**711**	870
Depreciation and amortization expenses	**355**	300
Accretion on fixed asset removal and nuclear waste management liabilities	**313**	306
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(284)**	(271)
Property taxes	**13**	12
	1,108	1,217
Income before other gains, interest and income taxes	**677**	297
Other gains	**(16)**	(3)
Income before interest and income taxes	**693**	300
Net interest expense *(Note 4)*	**56**	45
Income before income taxes	**637**	255
Income tax expense	**128**	30
Net income	**509**	225
Net income attributable to the Shareholder	**505**	221
Net income attributable to non-controlling interest	**4**	4
Basic and diluted earnings per share *(dollars)* [1]	**1.84**	0.80

[1] The weighted average number of shares outstanding as at March 31, 2025 and 2024 was 274.6 million. There were no dilutive securities during the three months ended March 31, 2025 and 2024.

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

Three Months Ended March 31 *(millions of dollars)*	**2025**	**2024**
Net income	**509**	225
Other comprehensive income, net of income taxes *(Note 7)*		
Reclassification to income of amounts related to pension and other post-employment benefits [1]	**-**	(1)
Reclassification to income of amount related to derivatives designated as cash flow hedges [2]	**-**	(1)
Net loss on derivatives designated as cash flow hedges [3]	**(6)**	(7)
Currency translation adjustment	**(3)**	49
Other comprehensive income for the period	**(9)**	40
Comprehensive income	**500**	265
Comprehensive income attributable to the Shareholder	**496**	261
Comprehensive income attributable to non-controlling interest	**4**	4

[1] Net of income tax recovery of nil for each of the three months ended March 31, 2025 and 2024.
[2] Net of income tax recovery of nil for each of the three months ended March 31, 2025 and 2024.
[3] Net of income tax recovery of $2 million for each of the three months ended March 31, 2025 and 2024.

See accompanying notes to the interim consolidated financial statements.

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Three Months Ended March 31 *(millions of dollars)*	**2025**	**2024**
Operating activities		
Net income	**509**	225
Adjust for non-cash items:		
Depreciation and amortization expenses	**355**	300
Accretion on fixed asset removal and nuclear waste management liabilities	**313**	306
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(284)**	(271)
Pension and other post-employment benefit costs *(Note 8)*	**78**	91
Deferred income tax (recovery) expense	**(21)**	1
Regulatory assets and regulatory liabilities	**44**	(2)
Other	**(14)**	(1)
Expenditures on fixed asset removal and nuclear waste management	**(178)**	(103)
Reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management	**64**	35
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	**(74)**	(67)
Net changes to other long-term assets and long-term liabilities	**65**	29
Net changes in non-cash working capital balances *(Note 13)*	**(103)**	21
Cash flow provided by operating activities	**754**	564
Investing activities		
Investment in property, plant and equipment and intangible assets	**(1,082)**	(680)
Acquisition of Lightstar Renewables and Lightstar Operations One	**-**	(131)
Proceeds from sale of interest in joint venture	**11**	-
Cash flow used in investing activities	**(1,071)**	(811)
Financing activities		
Issuance of long-term debt *(Note 4)*	**994**	77
Repayment of long-term debt *(Note 4)*	**-**	(400)
Issuance of short-term debt *(Note 5)*	**1,241**	415
Repayment of short-term debt *(Note 5)*	**(665)**	(400)
Distribution to non-controlling interest	**(4)**	(5)
Equity investment from non-controlling interest	**-**	1
Cash flow provided by (used in) financing activities	**1,566**	(312)
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**-**	4
Net increase (decrease) in cash, cash equivalents and restricted cash	**1,249**	(555)
Cash, cash equivalents and restricted cash, beginning of period	**1,363**	1,481
Cash, cash equivalents and restricted cash, end of period	**2,612**	926

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	March 31 2025	December 31 2024
Assets		
Current assets		
Cash, cash equivalents and restricted cash	**2,612**	1,363
Equity securities	**167**	159
Receivables from related parties	**634**	616
Nuclear fixed asset removal and nuclear waste management funds	**349**	283
Fuel inventory	**424**	297
Materials and supplies	**178**	145
Regulatory assets *(Note 3)*	**540**	540
Prepaid expenses	**252**	292
Other current assets	**209**	388
	5,365	4,083
Property, plant and equipment	**52,616**	51,290
Less: accumulated depreciation	**15,418**	15,159
	37,198	36,131
Intangible assets	**1,041**	1,029
Less: accumulated amortization	**463**	439
	578	590
Goodwill	**230**	230
Other assets		
Nuclear fixed asset removal and nuclear waste management funds	**22,284**	22,129
Loan receivable from related party	**901**	902
Long-term materials and supplies	**319**	355
Regulatory assets *(Note 3)*	**4,328**	4,367
Investments subject to significant influence	**43**	52
Other long-term assets	**143**	137
	28,018	27,942
	71,389	68,976

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	March 31 2025	December 31 2024
Liabilities		
Current liabilities		
Accounts payable, accrued charges and other payables	**2,174**	2,068
Short-term debt *(Note 5)*	**791**	215
Long-term debt due within one year *(Note 4)*	**604**	604
Regulatory liabilities *(Note 3)*	**246**	246
	3,815	3,133
Long-term debt *(Note 4)*	**12,097**	11,103
Other liabilities		
Fixed asset removal and nuclear waste management liabilities *(Note 6)*	**26,202**	26,042
Pension liabilities	**1**	46
Other post-employment benefit liabilities	**2,749**	2,716
Long-term accounts payable and accrued charges	**402**	382
Deferred revenue	**353**	355
Deferred income taxes	**2,481**	2,461
Regulatory liabilities *(Note 3)*	**995**	939
	33,183	32,941
Equity		
Common shares [1]	**5,126**	5,126
Class A shares [2]	**787**	787
Contributed surplus	**27**	28
Retained earnings	**15,974**	15,469
Accumulated other comprehensive income *(Note 7)*	**184**	193
Equity attributable to the Shareholder	**22,098**	21,603
Equity attributable to non-controlling interest	**196**	196
Total equity	**22,294**	21,799
	71,389	68,976

[1] 256,300,010 Common shares outstanding at a stated value of $5,126 million as at March 31, 2025 and December 31, 2024.
[2] 18,343,815 Class A shares outstanding at a stated value of $787 million as at March 31, 2025 and December 31, 2024.

Commitments and Contingencies *(Notes 4, 5, 8 and 11)*

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY (UNAUDITED)

Three Months Ended March 31 *(millions of dollars)*	**2025**	**2024**
Common shares	**5,126**	5,126
Class A shares	**787**	787
Contributed surplus		
Balance at beginning of period	**28**	30
Reclassification to income of amounts related to gain on deconsolidation of Fair Hydro Trust	**(1)**	(1)
Balance at end of period	**27**	29
Retained earnings		
Balance at beginning of period	**15,469**	14,481
Net income attributable to the Shareholder	**505**	221
Balance at end of period	**15,974**	14,702
Accumulated other comprehensive income, net of income taxes *(Note 7)*		
Balance at beginning of period	**193**	(15)
Other comprehensive (loss) income	**(9)**	40
Balance at end of period	**184**	25
Equity attributable to the Shareholder	**22,098**	20,669
Equity attributable to non-controlling interest		
Balance at beginning of period	**196**	182
Equity investment from non-controlling interest	**-**	6
Income attributable to non-controlling interest	**4**	4
Distribution to non-controlling interest	**(4)**	(5)
Balance at end of period	**196**	187
Total equity	**22,294**	20,856

See accompanying notes to the interim consolidated financial statements

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. BASIS OF PRESENTATION

These interim consolidated financial statements for the three months ended March 31, 2025 and 2024 include the accounts of Ontario Power Generation Inc. (OPG or the Company) and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control and attributes the results to its sole shareholder, the Province of Ontario (the Province or the Shareholder). These interim consolidated financial statements have been prepared and presented in accordance with United States generally accepted accounting principles (US GAAP). These interim consolidated financial statements do not contain all of the disclosures required by US GAAP for annual financial statements. Accordingly, they should be read in conjunction with the annual consolidated financial statements of the Company as at and for the year ended December 31, 2024.

All dollar amounts are presented in Canadian dollars, unless otherwise noted. Certain 2024 comparative amounts have been reclassified from consolidated financial statements previously presented to conform to the 2025 interim consolidated financial statement presentation.

Seasonal Variations

OPG's quarterly electricity generation from the Regulated – Hydroelectric Generation, Contracted Hydroelectric and Other Generation, and Atura Power business segments is affected by changes in grid-supplied electricity demand. Changes in grid-supplied electricity demand are primarily caused by variations in seasonal weather conditions, changes in economic conditions, the impact of small-scale generation embedded in distribution networks, and the impact of conservation efforts. Historically, there has been greater electricity demand in Ontario during the winter and summer months due to heating and air conditioning demands.

OPG's quarterly electricity generation from hydroelectric facilities is impacted by weather conditions that affect water flows. Historically, there have been higher water flows in the second quarter as a result of snow and ice melt entering the river systems. The financial impact of variability in water flows on the Regulated – Hydroelectric Generation business segment is mitigated by regulatory deferral and variance accounts (regulatory accounts) authorized by the Ontario Energy Board (OEB).

The financial impact of variability in electricity generation from the Contracted Hydroelectric and Other Generation business segment and the Atura Power business segment is mitigated by the terms of the applicable Energy Supply Agreements with the Independent Electricity System Operator (IESO) for the contracted generating facilities in Ontario.

2. SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

The accounting policies followed in the presentation of these interim consolidated financial statements are consistent with those of the previous fiscal year.

Recent Accounting Pronouncements Not Yet Adopted

Improvements to Income Tax Disclosures

In December 2023, the Financial Accounting Standards Board (FASB) issued Accounting Standard Update (ASU) 2023-09, *Improvements to Income Tax Disclosures* (ASU 2023-09), an update to Topic 740, *Income Taxes*. The purpose of ASU 2023-09 is to enhance the transparency and decision usefulness of income tax disclosures through increasing disclosure requirements related to the rate reconciliation and income taxes paid information. The update requires specific categories to be disclosed in the rate reconciliation and additional information for reconciling items that meet a quantitative threshold. The update also requires that entities disclose income taxes paid disaggregated by federal, provincial and foreign taxes and by individual jurisdiction in which income tax paid exceeds five percent of total income taxes paid. The update is effective for annual periods beginning after December 15, 2024. Based on OPG's assessment as at December 31, 2024, this update is not expected to have a material impact on the disclosures contained in the Company's consolidated financial statements.

Disaggregation of Income Statement Expenses

In November 2024, the FASB issued ASU 2024-03, *Disaggregation of Income Statement Expenses*, an update to Subtopic 220-40, *Income Statement – Reporting Comprehensive Income – Expense Disaggregation Disclosures*. The purpose of the standard update is to improve the disclosures about a public business entity's expenses by requiring more detailed information about the types of expenses (including purchases of inventory and employee compensation) included within consolidated income statement expense captions. The update is effective for fiscal years beginning after December 15, 2026 and interim periods beginning after December 15, 2027. Early adoption is permitted. The standard update is to be applied prospectively with the option for retrospective application. The Company is currently evaluating the impact of adoption of the standard update on the disclosures contained within the Company's annual and interim consolidated financial statements.

3. REGULATORY ASSETS AND REGULATORY LIABILITIES

The regulatory assets and regulatory liabilities consist of the following:

As at *(millions of dollars)*	March 31 2025	December 31 2024
Regulatory assets		
Deferral and variance accounts authorized by the OEB		
Rate Smoothing Deferral Account	**684**	677
Nuclear Liability Deferral Account	**502**	520
Capacity Refurbishment Variance Account	**460**	460
Pension & OPEB Cash Versus Accrual Differential Deferral Account	**322**	376
Hydroelectric Surplus Baseload Generation Variance Account	**281**	307
Pickering B Extension Variance Account	**138**	131
Nuclear Development Variance Account	**81**	85
Other deferral and variance accounts [1]	**173**	174
	2,641	2,730
Deferred income taxes	**2,192**	2,151
Other	**35**	26
Total regulatory assets	**4,868**	4,907
Less: current portion	**540**	540
Non-current regulatory assets	**4,328**	4,367
Regulatory liabilities		
Deferral and variance accounts authorized by the OEB		
Pension and OPEB Cost Variance Account	**415**	411
Pension & OPEB Cash Payment Variance Account	**295**	321
Hydroelectric Water Conditions Variance Account	**184**	173
Nuclear Deferral and Variance Over/Under Recovery Variance Account	**76**	61
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges Variance Account	**55**	51
Other deferral and variance accounts [2]	**205**	152
	1,230	1,169
Pension and OPEB Regulatory Liability *(Note 8)*	**11**	16
Total regulatory liabilities	**1,241**	1,185
Less: current portion	**246**	246
Non-current regulatory liabilities	**995**	939

[1] Represents amounts for the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, Clarington Corporate Campus Deferral Account, Fitness for Duty Deferral Account, Pickering Closure Costs Deferral Account, Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account, Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account and Impact Resulting from Changes to Pickering Station End-of-Life Dates Deferral Account (December 31, 2017).

[2] Represents amounts for the Income and Other Taxes Variance Account, SR&ED ITC Variance Account, Ancillary Services Net Revenue Variance Account, Sale of Unprescribed Kipling Site Deferral Account and Bruce Lease Net Revenues Variance Account.

In January 2025, the Province released a proposal for potential amendments to *Ontario Regulation 53/05* intended to clarify the scope of the Pickering B Extension Variance Account to ensure that OPG can record costs incurred beginning in 2024 to retain the capacity and readiness to operate Units 5 to 8 of the Pickering nuclear generating station upon refurbishment, subject to the requisite approvals. The comment period for the proposal ended on March 14, 2025.

In April 2025, the Province released a proposal for potential amendments to *Ontario Regulation 53/05* to allow for the creation of a new variance account to record pre-development expenses for proposed hydroelectric projects by OPG. The comment period for the proposal ends on June 13, 2025.

Under the current OEB rate-setting framework, OPG begins recovering costs through regulated prices once projects are placed in-service. In May 2025, the Province proposed potential changes in regulations that would establish a new mechanism for concurrent cost recovery to allow OPG to recover debt interest during the construction period of the Darlington New Nuclear Project (DNNP) and also the Pickering Refurbishment project (if the project is approved to proceed). The proposed change would also prescribe a new OEB-regulated generator and establish the applicable rate-setting framework to enable OPG to enter into commercial partnerships for the DNNP. The comment period for the proposal ends on June 26, 2025.

4. LONG-TERM DEBT AND NET INTEREST EXPENSE

Long-term debt consists of the following:

As at *(millions of dollars)*	**March 31 2025**	**December 31 2024**
Medium Term Note Program senior notes	**6,950**	5,950
Senior notes payable under corporate credit facilities	**2,859**	2,859
Lower Mattagami Energy Limited Partnership senior notes	**1,995**	1,995
PSS Generating Station Limited Partnership senior notes	**245**	245
UMH Energy Partnership senior notes	**160**	160
OPG Eagle Creek Holdings LLC and subsidiaries senior notes	**516**	516
Other	**25**	25
	12,750	11,750
Less: unamortized bond issuance fees	**(49)**	(43)
Less: amounts due within one year	**(604)**	(604)
Long-term debt	**12,097**	11,103

For the three months ended March 31, 2025, net issuance of long-term debt under the Company's corporate credit facilities was nil (March 31, 2024 – net repayment of $323 million), which comprised nil repayments (March 31, 2024 – $400 million) and nil issuances (March 31, 2024 – $77 million). On April 2, 2025, OPG issued $172 million of senior notes under the Company's corporate credit facilities.

On March 13, 2025, OPG issued $1 billion of green bonds under its Sustainable Finance Framework, through its Medium Term Note Program. The issuance consisted of $500 million of senior notes maturing in March 2035, with a coupon interest rate of 4.32 percent, and $500 million of senior notes maturing in March 2055, with a coupon interest rate of 4.87 percent. The net proceeds from the issuance were used to finance or re-finance Eligible Green Projects as defined under the Sustainable Finance Framework.

Proceeds from OPG's green bond issuances are restricted in purpose and are to be used to finance or re-finance Eligible Green Projects as defined under OPG's Sustainable Finance Framework and are held in a segregated account. As of March 31, 2025, restricted cash was $4 million, of which $4 million is from green bond issuance proceeds. In March 2025, approximately $992 million were released from the segregated account, representing funds invested in the eligible projects.

On April 8, 2025, long-term debt of $400 million matured under the Company's Medium Term Note Program.

Net Interest Expense

The following table summarizes the net interest expense:

(millions of dollars)	Three Months Ended March 31 2025	2024
Interest on long-term debt	**108**	92
Interest on short-term debt	**6**	4
Interest income	**(20)**	(23)
Interest capitalized to property, plant and equipment and intangible assets	**(30)**	(28)
Interest related to regulatory assets and regulatory liabilities [1]	**(8)**	-
Net interest expense	**56**	45

[1] Includes interest to recognize the cost of financing regulatory account balances as authorized by the OEB, and interest costs deferred in certain regulatory accounts.

5. SHORT-TERM DEBT

Committed credit facilities and maturity dates as at March 31, 2025 were as follows:

(millions of dollars)		Amount	Maturity
Bank facilities:			
Corporate		**1,211**	September 2027 and May 2029 [1]
Corporate	US Dollars	**750**	November 2025 [2]
Lower Mattagami Energy Limited Partnership		**460**	June 2029 [3]
OPG Eagle Creek Holdings LLC and subsidiaries	US Dollars	**20**	October 2028
Ontario Financing Authority facility		**1,250**	December 2029 [1]
Ontario Electricity Financial Corporation facility		**750**	December 2026 [1]

[1] Represents amounts available under the facility net of debt issuances. Of the total credit facilities, $211 million matures by September 2027 and is available to finance certain expenditures of the DNNP, subject to certain conditions, and $1,000 million matures in May 2029.
[2] The facility has a one-year extension option beyond the maturity date of November 2025.
[3] A letter of credit of $60 million was outstanding under this facility as at March 31, 2025.

Short-term debt consists of the following:

As at *(millions of dollars)*	March 31 2025	December 31 2024
Lower Mattagami Energy Limited Partnership	**200**	215
Corporate commercial paper	**591**	-
Total short-term debt	**791**	215

As of March 31, 2025, a total of $510 million of letters of credit had been issued (December 31, 2024 – $504 million). As of March 31, 2025, this included $314 million for the supplementary pension plans, $60 million for Lower Mattagami Energy Limited Partnership, $58 million for general corporate purposes, $43 million for Atura Power, $19 million for OPG Eagle Creek Holdings LLC and its subsidiaries, $14 million for UMH Energy Partnership, $1 million for PSS Generating Station Limited Partnership and $1 million for PowerON Energy Solutions LP.

On April 23, 2025, OPG issued $217 million of letters of credit for general corporate purposes to support the DNNP.

The weighted average interest rate on the short-term debt as at March 31, 2025 is 3.02 percent (December 31, 2024 – 3.71 percent).

6. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

Liabilities for fixed asset removal and nuclear waste management on a present value basis consist of the following:

As at *(millions of dollars)*	March 31 2025	December 31 2024
Liability for used nuclear fuel management	**16,112**	15,991
Liability for nuclear decommissioning and nuclear low and intermediate level waste management	**9,816**	9,782
Liability for non-nuclear fixed asset removal	**274**	269
Fixed asset removal and nuclear waste management liabilities	**26,202**	26,042

7. ACCUMULATED OTHER COMPREHENSIVE INCOME

The changes in the balance of each component of accumulated other comprehensive income (loss) (AOCI), net of income taxes were as follows:

	Three Months Ended March 31, 2025			
(millions of dollars)	Unrealized Gains and Losses on Cash Flow Hedges	Pension and OPEB	Currency Translation Adjustment	Total
Balance, beginning of period	**5**	**6**	**182**	**193**
Net loss on cash flow hedges	**(6)**	**-**	**-**	**(6)**
Translation of foreign operations	**-**	**-**	**(3)**	**(3)**
Other comprehensive loss for the period	**(6)**	**-**	**(3)**	**(9)**
Balance, end of period	**(1)**	**6**	**179**	**184**

	Three Months Ended March 31, 2024			
(millions of dollars)	Unrealized Gains and Losses on Cash Flow Hedges	Pension and OPEB	Currency Translation Adjustment	Total
Balance, beginning of period	9	(33)	9	(15)
Net loss on cash flow hedges	(7)	-	-	(7)
Amounts reclassified from AOCI	(1)	(1)	-	(2)
Translation of foreign operations	-	-	49	49
Other comprehensive (loss) income for the period	(8)	(1)	49	40
Balance, end of period	1	(34)	58	25

The significant amounts reclassified out of each component of AOCI, net of income taxes, were as follows:

(millions of dollars)	Amount Reclassified from AOCI for the Three Months Ended March 31 2025	2024	Statement of Income Line Item
Amortization of amounts related to cash flow hedges			
Gains	**-**	(1)	Revenue and Net interest expense
	-	(1)	
Amortization of amounts related to pension and OPEB			
Net actuarial gains, net of past service costs	**-**	(1)	See (1) below
	-	(1)	
Total reclassifications for the period	**-**	(2)	

[1] These AOCI components are included in the computation of pension and OPEB costs (see Note 8 for additional details).

Existing pre-tax net losses for derivatives of nil deferred in AOCI as at March 31, 2025 are expected to be reclassified to net income within the next 12 months.

8. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

OPG's pension and other post-employment benefit (OPEB) costs for the three months ended March 31, 2025 and 2024 were as follows:

(millions of dollars)	Registered Pension Plans 2025	2024	Supplementary Pension Plans 2025	2024	Other Post-Employment Benefits 2025	2024
Components of Cost Recognized for the period						
Current service costs	**74**	76	**2**	2	**26**	25
Interest on projected benefit obligation	**192**	198	**5**	4	**32**	33
Expected return on plan assets, net of expenses	**(269)**	(258)	**-**	-	**-**	-
Amortization of past service costs [1]	**-**	-	**-**	-	**1**	1
Amortization of net actuarial loss (gain)[1]	**-**	-	**1**	1	**(7)**	(8)
Costs recognized [2]	**(3)**	16	**8**	7	**52**	51

[1] The net impact of amortization of past service costs and net actuarial loss (gain) is recognized as an increase (a decrease) to other comprehensive income. This decrease in the first quarter of 2025 was partially offset by a decrease in the Pension and OPEB Regulatory Liability of $5 million (three months ended March 31, 2024 – increase in the Pension and OPEB Regulatory Asset of $5 million).

[2] These pension and OPEB costs for the three months ended March 31, 2025, exclude the net addition of costs of $21 million resulting from the recognition of changes in the regulatory liabilities for the Pension & OPEB Cost Variance Account, the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account (three months ended March 31, 2024 – net addition of costs of $17 million).

9. RISK MANAGEMENT AND DERIVATIVES

OPG is exposed to risks related to changes in market interest rates on debt, movements in foreign currency that affect the Company's assets, liabilities and forecasted transactions, and fluctuations in commodity prices. Select derivative instruments are used to manage such risks. Derivatives are used as hedging instruments, as well as for trading purposes.

Interest Rates

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in interest rates. Interest rate risk for OPG arises with the need to refinance existing debt or undertake new financing. The management of these risks includes using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

Foreign Exchange

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as certain materials, services and fuels purchased for generating stations and major development projects, as well as debt issuances, may be denominated in, or tied to, US dollars. To manage this risk, the Company employs various financial instruments such as forwards and other derivative contracts, in accordance with approved corporate risk management policies. Additionally, volatility in the Canadian/US foreign exchange rate also impacts OPG's financial results from certain of its subsidiaries, whose operations are based exclusively in the US.

Commodity Prices

OPG is exposed to fluctuations in commodity prices. Changes in the market prices of nuclear fuels, oil, gas and biomass used to produce electricity can adversely impact OPG's earnings and cash flow provided by operating activities. To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts.

A number of OPG's hydroelectric facilities in the US are exposed to the wholesale electricity market and, therefore, are subject to volatility of wholesale electricity market pricing. Although revenue from these facilities represents a small portion of OPG's overall revenue, the Company may enter into derivative instruments from time to time to further mitigate this risk.

Credit

The Company's credit risk exposure is primarily a function of its electricity and other sales. The majority of OPG's revenue is derived from electricity sales through the IESO administered market. Market participants in the IESO market provide collateral in accordance with the IESO prudential support requirements to cover funds that they might owe to the market. Although the credit exposure to the IESO represents a significant portion of OPG's accounts receivable, the risk is considered acceptable due to the IESO's primary role in the Ontario electricity market. The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts was $1 million as at March 31, 2025 (December 31, 2024 – less than $1 million).

The fair value of the derivative instruments totalled a net liability of $24 million as at March 31, 2025 (December 31, 2024 − $17 million).

10. FAIR VALUE MEASUREMENTS

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial assets and liabilities into three levels, based on the inputs used in measuring the fair value of the financial assets and liabilities. The fair value hierarchy has the following levels:

- Level 1: Valuation of inputs is based on unadjusted quoted market prices observed in active markets for identical assets or liabilities.
- Level 2: Valuation is based on inputs other than quoted prices under Level 1 that are observable for the asset or liability, either directly or indirectly.
- Level 3: Valuation is based on inputs for the asset or liability that are not based on observable market data.

The fair value of financial instruments traded in active markets is based on quoted market prices as at the interim consolidated balance sheet dates. A market is regarded as active if quoted prices are readily and regularly available from an exchange, dealer, broker, industry group, pricing service or regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's-length basis. The quoted market price used for financial assets held by OPG is the current bid price. These instruments are included in Level 1 and consist primarily of equity investments and fund investments.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing as at the interim consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives and fund investments. Various other fund investments are valued at the unit values supplied by the fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and, therefore, do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If all significant inputs required to fair value an instrument are observable, the instrument is included in Level 2.

If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. Specific valuation techniques are used to value these instruments. Significant Level 3 inputs include: recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions and other relevant factors.

A summary of OPG's financial instruments and their fair value as at March 31, 2025 and December 31, 2024 was as follows:

	Fair Value		Carrying Value [1]		
(millions of dollars)	**2025**	**2024**	**2025**	**2024**	**Balance Sheet Line Item**
Nuclear Segregated Funds (includes current portion) [2]	**22,633**	22,412	**22,633**	22,412	Nuclear fixed asset removal and nuclear waste management funds
Loan receivable - from Fair Hydro Trust	**839**	828	**901**	902	Loan receivable from related party
Investment in Hydro One Limited Shares	**167**	159	**167**	159	Equity securities
Long-term debt (includes current portion)	**(12,273)**	(11,204)	**(12,701)**	(11,707)	Long-term debt
Other financial instruments	**121**	129	**121**	129	Various

[1] The carrying values of other financial instruments included in cash and cash equivalents, receivables from related parties, other current assets, short-term debt, and accounts payable, accrued charges and other payables approximate their fair values due to the immediate or short-term maturity of these financial instruments.

[2] The Nuclear Segregated Funds are comprised of the Decommissioning Segregated Fund and the Used Fuel Segregated Fund. OPG's fair value of the Nuclear Segregated Funds is set not to exceed an amount equal to the funding liability pursuant to the Ontario Nuclear Funds Agreement when the Nuclear Segregated Funds are in a surplus position.

The fair value of OPG's long-term debt issued under the Medium Term Note Program is based on indicative pricing from the market. The fair value of these debt instruments is based on Level 2 inputs. The fair value of all other long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs.

The following tables present financial assets and financial liabilities measured at fair value in accordance with the fair value hierarchy:

As at	March 31, 2025			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**6,453**	**7,322**	**-**	**13,775**
Investments measured at NAV [1]				**4,829**
				18,604
Due to Province				**(5,733)**
Used Fuel Segregated Fund, net				**12,871**
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**4,946**	**5,615**	**-**	**10,561**
Investments measured at NAV [1]				**3,781**
				14,342
Due to Province				**(4,580)**
Decommissioning Segregated Fund, net				**9,762**
Equity securities	**167**	**-**	**-**	**167**
Other financial assets	**60**	**-**	**102**	**162**
Liabilities				
Other financial liabilities	**(41)**	**-**	**-**	**(41)**

As at	December 31, 2024			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	7,030	6,676	-	13,706
Investments measured at NAV [1]				4,722
				18,428
Due to Province				(5,691)
Used Fuel Segregated Fund, net				12,737
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	5,362	5,156	-	10,518
Investments measured at NAV [1]				3,702
				14,220
Due to Province				(4,545)
Decommissioning Segregated Fund, net				9,675
Equity securities	159	-	-	159
Other financial assets	73	-	97	170
Liabilities				
Other financial liabilities	(41)	-	-	(41)

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the interim consolidated balance sheets.

During the three months ended March 31, 2025, there were no transfers between Level 1 and Level 2 and into or out of Level 3.

The changes in the net assets measured at fair value that are classified as Level 3 financial instruments for the three months ended March 31, 2025 were as follows:

(millions of dollars)	**Other financial instruments**
Opening balance, January 1, 2025	**97**
Realized losses included in revenue	**(1)**
Purchases	**6**
Closing balance, March 31, 2025	**102**

Investments Measured at Net Asset Value

Nuclear Segregated Funds

Nuclear Segregated Funds' investments classified as Level 3 consist of real estate, infrastructure, other real assets and private debt investments. The fair value of these investments is determined using financial information as provided by the general partners of the limited partnership funds in which the Nuclear Segregated Funds are invested. Direct investments are valued using appropriate valuation techniques, such as recent arm's-length market transactions, references to current fair values of other instruments that are substantially the same, discounted cash flow analyses, third-party independent appraisals, valuation multiples, or other valuation methods. Any control, size, liquidity or other discount premiums on the investments are considered in the determination of fair value.

The process of valuing investments for which no published market price exists is based on inherent uncertainties and the resulting values may differ from values that would have been used had a ready market existed for these investments. The values may also differ from the prices at which the investments may be sold.

The classes of investments within the Nuclear Segregated Funds that are reported on the basis of Net Asset Value (NAV) as at March 31, 2025 were as follows:

(millions of dollars except where noted)	**Fair Value**	**Unfunded Commitments**	**Redemption Frequency**	**Redemption Notice**
Real Assets				
Infrastructure	**4,697**	**1,639**	**n/a**	**n/a**
Real Estate	**3,280**	**1,272**	**n/a**	**n/a**
Private Debt	**207**	**800**	**n/a**	**n/a**
Other	**426**	**16**	**n/a**	**n/a**
Pooled Funds				
Fixed Income	**2,432**	**n/a**	**Daily**	**1-5 days**
Equity	**956**	**n/a**	**Daily**	**1-5 days**
Total	**11,998**	**3,727**		

The fair value of the pooled funds is classified as Level 2. Infrastructure, real estate, other real assets and private debt investments are measured using NAV as a practical expedient for determining their fair value.

11. COMMITMENTS AND CONTINGENCIES

Litigation

Various legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of business activities. Each of these matters are subject to various uncertainties. Some of these matters may be resolved unfavourably. While it is not possible to determine the ultimate outcome of the various pending actions, it is the Company's belief that their resolution is not likely to have a material adverse impact on its interim consolidated financial position.

Guarantees

As at March 31, 2025, the total amount of guarantees provided by OPG was nil (December 31, 2024 – $30 million).

Contractual Obligations

OPG's contractual obligations as at March 31, 2025 were as follows:

(millions of dollars)	**2025** [1]	**2026**	**2027**	**2028**	**2029**	**Thereafter**	**Total**
Fuel supply agreements	67	211	207	142	136	321	1,084
Contributions to the OPG registered pension plan [2]	94	128	-	-	-	-	222
Long-term debt repayment	604	674	530	269	505	10,168	12,750
Interest on long-term debt	364	466	456	436	425	5,893	8,040
Short-term debt repayment	795	-	-	-	-	-	795
Commitments related to Darlington Refurbishment project [3]	149	-	-	-	-	-	149
Commitments related to Atura Power development projects [3]	505	111	5	17	-	-	638
Commitments related to Pickering Refurbishment project and DNNP [3]	695	-	-	-	-	-	695
Operating licences	42	61	63	61	62	179	468
Operating lease obligations	14	15	11	4	3	37	84
Accounts payable, accrued charges and other payables	1,768	9	10	9	10	284	2,090
Other	43	88	48	34	22	92	327
Total	5,140	1,763	1,330	972	1,163	16,974	27,342

[1] Represents amounts for the remainder of the year.

[2] The pension contributions include ongoing funding requirements in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2024. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2027. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment and the timing of funding valuations. Funding requirements after January 1, 2027 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time.

[3] Represents estimated currently committed costs to close the projects, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Contractual and commercial commitments as noted exclude certain purchase orders, as they represent purchase authorizations rather than legally binding contracts, and are subject to change without significant penalties.

12. BUSINESS SEGMENTS

For a detailed description of each reportable business segment, measure of profit and loss and the Company's Chief Operating Decision Maker, refer to OPG's annual consolidated financial statements as at and for the year ended December 31, 2024.

Segment Income (Loss)	**Regulated**			**Unregulated**				
For the Three Months Ended March 31, 2025 *(millions of dollars)*	**Nuclear Generation**	**Nuclear Sustainability Services**	**Hydroelectric Generation**	**Contracted Hydroelectric and Other Generation**	**Atura Power**	**Other**	**Elimination**	**Total**
Revenue	**1,132**	**-**	**408**	**231**	**344**	**12**	**-**	**2,127**
Leasing revenue	**7**	**-**	**-**	**-**	**-**	**1**	**-**	**8**
Other revenue	**-**	**36**	**-**	**(1)**	**-**	**48**	**(61)**	**22**
Total revenue	**1,139**	**36**	**408**	**230**	**344**	**61**	**(61)**	**2,157**
Fuel expense	**82**	**-**	**72**	**23**	**195**	**-**	**-**	**372**
Gross margin	**1,057**	**36**	**336**	**207**	**149**	**61**	**(61)**	**1,785**
Operations, maintenance and administration expenses	**505**	**36**	**101**	**78**	**23**	**29**	**(61)**	**711**
Depreciation and amortization expenses	**194**	**-**	**66**	**41**	**33**	**21**	**-**	**355**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**310**	**-**	**2**	**1**	**-**	**-**	**313**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(284)**	**-**	**-**	**-**	**-**	**-**	**(284)**
Property taxes	**7**	**-**	**-**	**5**	**-**	**1**	**-**	**13**
Other losses (gains)	**3**	**-**	**-**	**-**	**-**	**(19)**	**-**	**(16)**
Income (loss) before interest and income taxes	**348**	**(26)**	**169**	**81**	**92**	**29**	**-**	**693**
Net interest expense								**56**
Income before income taxes								**637**
Income tax expense								**128**
Net income								**509**

Segment Income (Loss)	**Regulated**			**Unregulated**				
For the Three Months Ended		**Nuclear**		**Contracted**				
March 31, 2024	**Nuclear**	**Sustainability**	**Hydroelectric**	**Hydroelectric and**				
(millions of dollars)	**Generation**	**Services**	**Generation**	**Other Generation**	**Atura Power**	**Other**	**Elimination**	**Total**
Revenue	893	-	384	204	235	9	-	1,725
Leasing revenue	7	-	-	-	-	1	-	8
Other revenue	-	36	-	6	-	51	(59)	34
Total revenue	900	36	384	210	235	61	(59)	1,767
Fuel expense	65	-	70	13	105	-	-	253
Gross margin	835	36	314	197	130	61	(59)	1,514
Operations, maintenance and administration expenses	673	36	101	72	20	27	(59)	870
Depreciation and amortization expenses	161	-	46	43	30	20	-	300
Accretion on fixed asset removal and nuclear waste management liabilities	-	303	-	2	1	-	-	306
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(271)	-	-	-	-	-	(271)
Property taxes	6	-	-	5	1	-	-	12
Other gains	-	-	-	(3)	-	-	-	(3)
(Loss) income before interest and income taxes	(5)	(32)	167	78	78	14	-	300
Net interest expense								45
Income before income taxes								255
Income tax expense								30
Net income								225

Selected Interim Consolidated Balance Sheets information as at March 31, 2025 *(millions of dollars)*	**Regulated**		**Unregulated**				
	Nuclear Generation	**Nuclear Sustainability Services**	**Hydroelectric Generation**	**Contracted Hydroelectric and Other Generation**	**Atura Power**	**Other**	**Total**
Segment property, plant and equipment in-service, net	**13,990**	**-**	**8,157**	**6,313**	**3,004**	**237**	**31,701**
Segment construction in progress	**3,993**	**-**	**511**	**134**	**591**	**268**	**5,497**
Segment property, plant and equipment, net	**17,983**	**-**	**8,668**	**6,447**	**3,595**	**505**	**37,198**
Segment intangible assets in-service, net	**45**	**-**	**2**	**244**	**93**	**142**	**526**
Segment development in progress	**16**	**-**	**-**	**1**	**-**	**35**	**52**
Segment intangible assets, net	**61**	**-**	**2**	**245**	**93**	**177**	**578**
Segment goodwill	**-**	**-**	**-**	**230**	**-**	**-**	**230**
Segment fuel inventory	**364**	**-**	**-**	**32**	**28**	**-**	**424**
Segment materials and supplies inventory							
Current	**175**	**-**	**-**	**3**	**-**	**-**	**178**
Long-term	**317**	**-**	**1**	**1**	**-**	**-**	**319**
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	**-**	**22,633**	**-**	**-**	**-**	**-**	**22,633**
Loan receivable	**-**	**-**	**-**	**-**	**-**	**901**	**901**
Fixed asset removal and nuclear waste management liabilities	**-**	**(25,928)**	**-**	**(164)**	**(55)**	**(55)**	**(26,202)**

Selected Consolidated Balance Sheets information as at December 31, 2024 *(millions of dollars)*	**Nuclear Generation**	**Regulated Nuclear Sustainability Services**	**Hydroelectric Generation**	**Unregulated Contracted Hydroelectric and Other Generation**	**Atura Power**	**Other**	**Total**
Segment property, plant and equipment in-service, net	14,046	-	8,189	6,322	3,033	224	31,814
Segment construction in progress	3,139	-	398	140	426	214	4,317
Segment property, plant and equipment, net	17,185	-	8,587	6,462	3,459	438	36,131
Segment intangible assets in-service, net	48	-	2	244	95	145	534
Segment development in progress	18	-	-	1	-	37	56
Segment intangible assets, net	66	-	2	245	95	182	590
Segment goodwill	-	-	-	230	-	-	230
Segment fuel inventory	231	-	-	39	27	-	297
Segment materials and supplies inventory							
Current	142	-	-	3	-	-	145
Long-term	352	-	-	3	-	-	355
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	-	22,412	-	-	-	-	22,412
Loan receivable	-	-	-	-	-	902	902
Fixed asset removal and nuclear waste management liabilities	-	(25,773)	-	(161)	(54)	(54)	(26,042)

Segment Capital Expenditure	**Regulated**		**Unregulated**				
(millions of dollars)	**Nuclear Generation**	**Nuclear Sustainability Services**	**Hydroelectric Generation**	**Contracted Hydroelectric and Other Generation**	**Atura Power**	**Other**	**Total**
Three months ended March 31, 2025							
Investment in property, plant and equipment and intangible assets	**940**	**-**	**124**	**34**	**167**	**77**	**1,342**
Net change in accruals and other non-cash items							**(260)**
Investment in property, plant and equipment and intangible assets - cash flow							**1,082**
Three months ended March 31, 2024							
Investment in property, plant and equipment and intangible assets	501	-	73	53	74	25	726
Net change in accruals and other non-cash items							(46)
Investment in property, plant and equipment and intangible assets - cash flow							680

13. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	Three Months Ended March 31 2025	2024
Receivables from related parties	**(18)**	142
Fuel Inventory	**(126)**	(76)
Materials and supplies	**(31)**	7
Prepaid expenses	**8**	(5)
Other current assets	**33**	15
Accounts payable, accrued charges and other payables	**31**	(62)
Net changes to non-cash working capital balances	**(103)**	21

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News from Ontario Power Generation

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March 4, 2025

OPG reports 2024 financial results

Strong progress continues on nuclear and hydroelectric refurbishments, and small modular reactors; new nuclear exploration launched at Wesleyville site

Toronto – Ontario Power Generation (OPG) is on track to deliver the Darlington Refurbishment Project on time and within the $12.8 billion budget. This significant accomplishment was part of OPG's reporting on its financial and operating results for 2024.

The electricity generator also reported a net income attributable to the Shareholder of $988 million, compared to $1,741 million for 2023. The decrease was expected and reflects the planned cyclical outage activities on Unit 2 of the Darlington nuclear generating station (Darlington GS) in 2024.

Darlington Nuclear Generating Station's Unit 1 Reactor Returned to Service from Refurbishment; Overall Project is on Time and Budget

Last fall, OPG returned the Darlington GS Unit 1 to full power after refurbishment, approximately five months ahead of schedule. The refurbishment team is now rebuilding the station's Unit 4, the final refurbishment unit, which is on track for completion in 2026, as scheduled.

"Though we faced unprecedented and unforeseeable external forces related to COVID-19 and inflation, our team was able to manage those costs through innovation and efficiency," said Nicolle Butcher, OPG President and CEO. "Now, in the ninth year of this 10-year execution phase, we are on time and on budget, clearly demonstrating our ability to responsibly execute large low-carbon energy projects, working with Ontario and Canada's robust domestic nuclear supply chains."

In addition, modifications made to Unit 1 during the refurbishment outage mean it is now capable of producing life-saving Cobalt-60 (Co-60) medical isotopes. The medical community uses this product to sterilize 30 percent of the world's single-use medical devices, including syringes, gloves and implants. The food industry also uses Co-60 to treat some foods against harmful bacteria and insects. The team will similarly modify the other three units of the Darlington GS to help produce Co-60.

Pickering Nuclear Generating Station Refurbishment Progressed to Definition Phase

OPG completed the initiation phase of Units 5 to 8 refurbishment at the Pickering nuclear generating station (Pickering GS) in the fourth quarter of 2024. Now, the team embarks on the project definition phase, during which OPG will complete a high-quality cost estimate and schedule for the project, progress detailed engineering, further procurement and contracting work, optimize project scope as well as develop a robust project execution plan.

As part of this work, OPG has entered into a number of contracts, including with Aecon Group Inc., AtkinsRéalis and BWXT Canada, for early engineering and procurement on the retube feeder and boiler replacement program.

“Working with trusted partners, including many who have helped us achieve project excellence on Darlington’s refurbishment, will assist in meeting our goals on Pickering’s refurbishment,” said Butcher. “The extensive planning and preparation underway will help ensure the final project, if approved by the Province and the Canadian Nuclear Safety Commission, is completed safely and with quality, on time and on budget.”

Darlington New Nuclear Project Update

OPG continues to advance the Darlington New Nuclear Project, with site preparation underway for four approximately 300-megawatt (MW) BWRX-300 small modular reactors (SMR). The Canadian Nuclear Safety Commission (CNSC) concluded its two-part Licence to Construct hearing for the first SMR in January 2025.

“Pending a regulatory decision from the CNSC and final approval from the Province, we are prepared to begin constructing the first reactor with the goal of deploying Canada’s first grid-scale SMR by the end of the decade,” said Butcher. “As first movers on the SMR technology, we hope to build a foundation for further growing Ontario and Canada’s nuclear supply chains.”

Strategic Sites for New Generation Update, Highlighting New Nuclear Potential at Wesleyville

In November 2024, the Province of Ontario (Province) asked OPG to begin discussions with Indigenous and municipal leaders to gauge community support for potential electricity generation at three OPG-owned sites: Wesleyville, Nanticoke and Lambton. All three sites are already zoned for electricity generation, are near transmission, and located in areas of Ontario experiencing significant growth.

In January 2025, with the First Nations’ willingness to enter discussions and following a formal expression of interest from Town of Port Hope, the Province has asked OPG to explore opportunities for new nuclear generation at the Wesleyville site. OPG also continues discussions with Indigenous rightsholders, local elected leaders and municipalities in the Nanticoke and Lambton areas.

“With electricity demand projected to grow by as much as 75% between now and 2050 we know there will be a need for new generation,” said Butcher. “Building and maintaining strong relationships with host communities and the Indigenous Nations on whose traditional territory and treaty territory we operate is key to the siting process. We

look forward to expanded conversations with Nations and municipalities to understand their perspectives and aspirations for their communities."

Hydroelectric Refurbishments

With the Province's announced support, OPG is moving forward with plans to refurbish and expand a number of hydroelectric generating stations across Northern Ontario over the next decade. When complete, this work will secure up to 830 MW of electricity in the North, enough to power approximately 830,000 homes.

This is part of OPG's plan to refurbish and redevelop hydroelectric generating stations across the province to maintain reliable and efficient operations and increase production of renewable energy for decades into the future.

"Many of our hydroelectric stations have been in service, generating the electricity Ontarians need, for decades and, in some cases, more than a century," said Butcher. "The work we are doing now and over the next number of years to renew our hydroelectric fleet will ensure those same stations reliably produce power for future generations to come."

Net Income Attributable to the Shareholder

Net income attributable to the Shareholder for 2024 was $988 million, a decrease of $753 million compared to 2023. The decrease was primarily attributable to expected lower earnings from the Regulated – Nuclear Generation business segment, driven by lower electricity generation and a lower base regulated price for OPG's nuclear electricity generation in effect during 2024 as previously approved by the Ontario Energy Board, higher operations, maintenance and administration expenses, and higher depreciation and amortization expenses.

The lower electricity generation was expected and primarily due to a planned cyclical maintenance outage on Unit 2 of the Darlington GS in the first half of 2024 and the end of commercial operation of Unit 1 of the Pickering GS on October 1, 2024, as planned, partially offset by fewer planned outage days at the Pickering GS.

Generating and Operating Performance

Electricity generated in 2024 was 82.1 terawatt hours (TWh) compared to 80.9 TWh in 2023.

Regulated – Nuclear Generation Segment

Electricity generation from the Regulated – Nuclear Generation business segment decreased by 3.1 TWh in 2024 compared to 2023, primarily due to higher planned and unplanned outage days at the Darlington GS and the end of commercial operation of Unit 1 of the Pickering GS, partially offset by higher electricity generation at the Pickering GS due to fewer planned outage days. Unit 4 of the Pickering GS ended commercial operation and was permanently taken offline on December 31, 2024, as planned.

The unit capability factor at the Darlington GS decreased from 97.0 per cent for 2023 to 74.6 per cent for 2024, primarily due to higher planned and unplanned outage days. The unit capability factor at the Pickering GS increased from 80.7 per cent for 2023 to 83.3 per cent for 2024, due to fewer planned outage days.

Regulated – Hydroelectric Generation Segment

Electricity generation from the Regulated – Hydroelectric Generation business segment increased by 1.1 TWh during 2024, compared to 2023, mainly due to higher electricity generation at the hydroelectric facilities in the Niagara region reflecting higher electricity demand, and higher water flows across most of Ontario.

Availability at the regulated hydroelectric stations for 2024 was comparable to 2023.

Contracted Hydroelectric and Other Generation Segment

Electricity generation from the Contracted Hydroelectric and Other Generation business segment in 2024 was comparable to 2023.

Availability of the hydroelectric stations in the segment for 2024 was 80.8 per cent, compared to 85.9 per cent for 2023. The decrease was primarily due to higher planned outages at the Lower Mattagami hydroelectric generating stations.

Atura Power Segment

Electricity generation from the Atura Power business segment increased by 3.4 TWh in 2024, compared to 2023, primarily due to higher demand for electricity generation from the combined cycle plants.

Thermal Availability of the generating stations in the segment decreased to 86.4 per cent as at December 31, 2024, compared to 89.5 per cent as at December 31, 2023, primarily due to a planned outage at the Halton Hills generating station.

Generation Development

OPG is undertaking a number of generation development and other projects to maximize the value of and expand its generating fleet in support of Ontario’s electricity system.

Darlington Refurbishment

The Darlington Refurbishment Project will extend the operating life of the four-unit Darlington GS by at least 30 years.

On November 27, 2024, following the successful completion of start-up activities, the refurbished Unit 1 was reconnected to the electricity grid, ahead of the original schedule. Unit 1 provides 878 MW of electricity to the province, enough to power approximately 875,000 homes.

The Unit 4 refurbishment is executing the third major segment, Reassembly, which includes the installation and reassembly of reactor components. The installation of calandria tubes was successfully completed in January 2025, and the installation of fuel channels and lower feeders is in progress. Unit 4 is the last Darlington GS unit to undergo refurbishment and is scheduled to be returned to service in 2026.

The total project costs, including the impacts of the COVID-19 pandemic and inflation, are on track to meet the $12.8 billion budget.

Pickering Refurbishment

On January 23, 2025, the Province announced its approval of OPG's plan to proceed with the project definition phase as the next step toward refurbishing Units 5 to 8 of the Pickering GS. OPG Board of Directors' (Board) approved budget for this work is $4.1 billion, bringing the total Board-approved budget for the project to date to $6.2 billion. During the definition phase, OPG will complete a high-quality cost estimate and schedule for the project, progress detailed engineering, further procurement and contracting work, continue to optimize project scope, and develop the project execution plan. The definition phase is expected to last through 2026.

Once refurbished, the Pickering GS would continue to provide over 2,000 MW of electricity, equivalent to powering approximately two million homes, to help meet Ontario's demand for electricity. The refurbishment is anticipated to be completed by the mid-2030s.

Further details on OPG's major projects can be found in Management's Discussion and Analysis as at and for the year ended December 31, 2024, section, *Core Business and Outlook* under the heading, *Project Excellence*.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(millions of dollars – except where noted)	**2024**	**2023**
Revenue	7,187	7,434
Fuel expense	1,049	974
Operations, maintenance and administration expenses	3,318	3,136
Depreciation and amortization expenses	1,270	1,071
Accretion on fixed asset removal and nuclear waste management liabilities	1,221	1,178
Earnings on nuclear fixed asset removal and nuclear waste management funds	(1,102)	(1,057)
Other net expenses (gains)	69	(66)
Earnings before interest and income taxes	1,362	2,198
Net interest expense	186	103
Income tax expense	170	336
Net Income	1,006	1,759
Net income attributable to the Shareholder	988	1,741
Net income attributable to non-controlling interest [1]	18	18
Earnings (loss) before interest and income taxes		
Electricity generating business segments	1,439	2,266
Regulated – Nuclear Sustainability Services	(108)	(110)
Other	31	42
Earnings before interest and income taxes	1,362	2,198
Cash flow provided by operating activities	2,211	2,538
Capital expenditures [2]	3,725	2,829
Electricity generation (TWh)		
Regulated – Nuclear Generation	33.0	36.1
Regulated – Hydroelectric Generation	32.5	31.4
Contracted Hydroelectric and Other Generation [3]	5.0	5.2
Atura Power	11.6	8.2
Total OPG electricity generation	82.1	80.9
Nuclear unit capability factor (per cent)		
Darlington Nuclear GS [4]	74.6	97.0
Pickering Nuclear GS	83.3	80.7
Availability (per cent)		
Regulated – Hydroelectric Generation	85.8	85.4
Contracted Hydroelectric and Other Generation – hydroelectric stations	80.8	85.9
Atura Power [5]	86.4	89.5
Equivalent forced outage rate		
Contracted Hydroelectric and Other Generation – thermal stations	3.8	1.8

[1] Relates to the following: 25 per cent interest of Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in Lower Mattagami Limited Partnership; 33 per cent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in PSS Generating Station Limited Partnership; 15 per cent and 5 per cent interests of corporations wholly owned by Six Nations of Grand River Development Corporation and the Mississaugas of the Credit First Nation, respectively, in Nanticoke Solar LP; and non-controlling interests in certain electricity generating facilities in the United States.

[2] Includes net changes in accruals; excludes the acquisition of the new corporate headquarters building and surrounding lands at 1908 Colonel Sam Drive in Oshawa, Ontario in February 2023.

[3] Includes OPG's proportionate share of electricity generation from co-owned and minority shareholdings in electricity generating facilities.

[4] Excludes nuclear unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 3 and Unit 1 of the Darlington GS were excluded from the reported planned and unplanned outage days during their refurbishment period of September 3, 2020 to July 17, 2023, and February 15, 2022 to November 27, 2024, respectively. Unit 4 of the Darlington GS has been excluded from the measure since commencing refurbishment on July 19, 2023.

[5] Reflects the thermal availability of combined cycle plants as at the year-end date, calculated on a three-year rolling average basis.

About OPG

As one of North America's largest, most diverse electricity generators, OPG invests in local economies and employs thousands of people across Ontario. OPG and its family of companies are advancing the development of new low-carbon technologies, refurbishment projects, and electrification initiatives to power the growing demands of a clean economy. Learn more about how the company is delivering these initiatives while prioritizing people, partnerships, and strong communities by reading OPG's Integrated ESG Annual Report.

Ontario Power Generation Inc.'s audited consolidated financial statements and Management's Discussion and Analysis as at and for the year ended December 31, 2024, can be accessed on OPG's web site (www.opg.com), the Canadian Securities Administrators' web site (www.sedarplus.com), or can be requested from the Company.

For further information, please contact:

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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

DECEMBER 31, 2024

ONTARIO POWER GENERATION

2024 YEAR-END REPORT

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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the audited consolidated financial statements and accompanying notes of Ontario Power Generation Inc. and its subsidiaries (OPG or Company) as at and for the year ended December 31, 2024. OPG's consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars, unless otherwise noted.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG has also received exemptive relief from the Ontario Securities Commission (OSC) that allows OPG to apply US GAAP instead of International Financial Reporting Standards (IFRS). In September 2022, the OSC approved an exemption which allows the Company to continue to apply US GAAP up to January 1, 2027. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2027. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP*. This MD&A is dated March 4, 2025.

Additional information about OPG, including the Company's Annual Information Form, is available on SEDAR+ at www.sedarplus.com and the Company's website at www.opg.com.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "budget", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could" and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks and uncertainties, including those set out in the section, *Risk Management*, and forecasts discussed in the section, *Core Business and Outlook*. All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station (GS) performance, availability and operating lives, fuel costs, surplus baseload generation (SBG), fixed asset removal and nuclear waste management obligations and costs, availability of facilities for the permanent disposal of used nuclear fuel and other nuclear waste, performance and earnings of segregated nuclear and OPG pension funds, refurbishment of existing facilities, development and construction of new facilities, acquisition transactions and other business expansion opportunities, performance of acquired businesses, divestiture transactions, defined benefit pension and other post-employment benefit (OPEB) obligations and costs, income taxes, proposed new legislation, government policy including tariffs and other trade restrictions, the ongoing evolution and growth of electricity industries and markets in Ontario, Canada and the United States of America (United States or US), the continued application and renewal of energy supply agreements (ESAs) with the Independent Electricity System Operator (IESO) and other contracts for non-regulated facilities, inflation, interest rates, foreign currency exchange rates, commodity prices, wholesale electricity market prices, environmental and other regulatory requirements, operating licence applications to the Canadian Nuclear Safety Commission (CNSC) and the Federal Energy Regulatory Commission (FERC), health, safety and environmental developments, changes in the Company's workforce, renewal of union collective agreements, business continuity events, the weather, climate change, technological change, geopolitical events, financing requirements and liquidity, funding sources, applications to the Ontario Energy Board (OEB) for regulated prices, the impact of regulatory decisions by the OEB, clean energy investment government programs, forecasts of earnings, cash flow, earnings before interest, income taxes, depreciation and amortization, gross margin, operations, maintenance and administration (OM&A) expenses and project and other expenditures, retention of critical talent, supply chain availability and capacity, and supplier and third party performance. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events or otherwise.

Use of Non-GAAP Financial Measures

The Company uses the following non-GAAP financial performance measures in the MD&A:

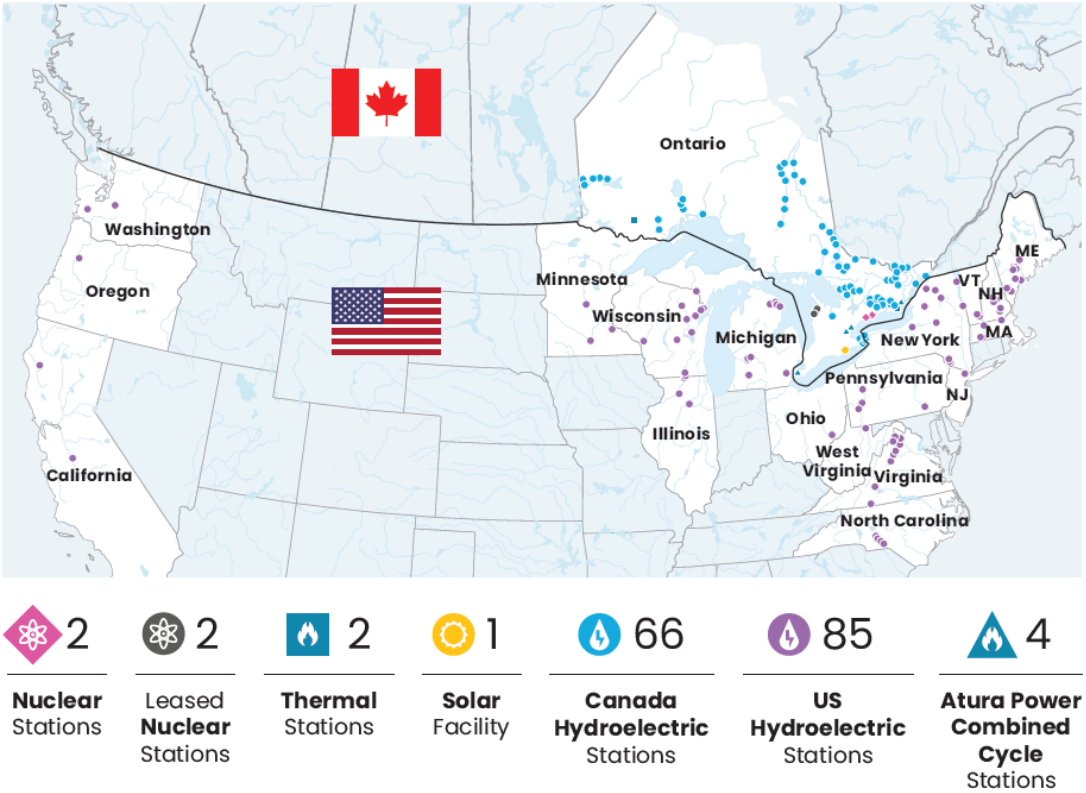
- "Earnings before Interest, Income Taxes, Depreciation and Amortization"; and
- "Gross Margin".

For a detailed description of each of the non-GAAP measures used in this MD&A, refer to the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*. The non-GAAP financial performance measures set out in this MD&A are intended to provide additional information to investors and do not have any standardized meaning under US GAAP, and therefore may not be comparable to other issuers, and should not be considered in isolation or as a substitute for measures of performance prepared under US GAAP.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder). OPG's electricity generation portfolio had an in-service generating capacity of 18,059 megawatts (MW) as at December 31, 2024.

As at December 31, 2024, OPG owned and operated two nuclear generating stations, 66 hydroelectric generating stations, two thermal generating stations, one solar facility and four combined-cycle gas turbine (combined cycle) plants in Ontario, Canada. The combined cycle plants are natural gas-fired facilities owned and operated through the Company's wholly-owned subsidiary operating as Atura Power. Through its US-based wholly-owned subsidiary, OPG Eagle Creek Holdings LLC (Eagle Creek), OPG also wholly or jointly owned and operated 85 hydroelectric generating stations and held minority interests in 14 hydroelectric and two solar facilities in the US as at December 31, 2024. In addition, OPG owned two nuclear generating stations in Ontario, the Bruce A GS and the Bruce B GS, (Bruce nuclear generating stations), which are leased on a long-term basis to, and operated by, Bruce Power L.P. (Bruce Power).

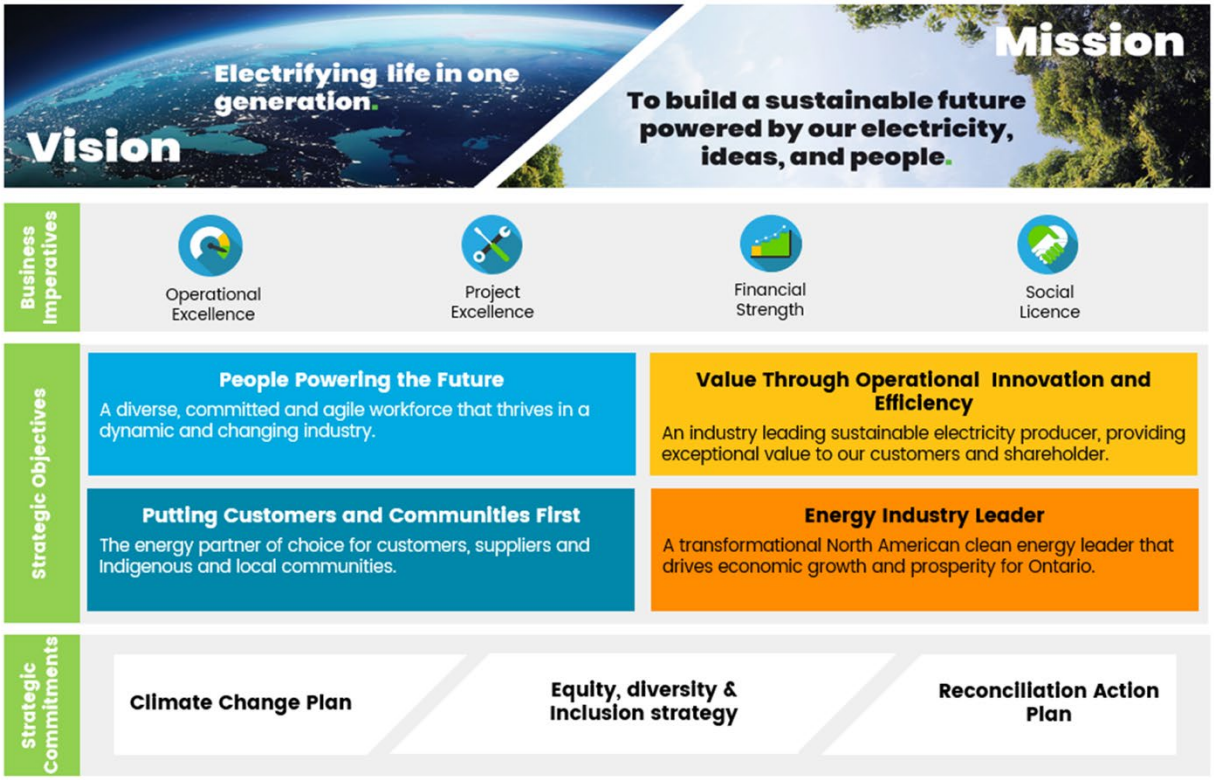


Income from co-owned and minority-held facilities is accounted for using the equity method of accounting. OPG's proportionate share of in-service generating capacity and electricity generation volume from co-owned and minority-held facilities are included in the Company's generation portfolio statistics set out in this MD&A.

Income from the generating stations leased to Bruce Power is included in revenue under the Regulated – Nuclear Generation business segment. The leased stations are not included in the Company's electricity generation and other operating statistics set out in this MD&A.

Corporate Strategy

OPG's mission is to build a sustainable future powered by our electricity, ideas, and people. OPG's vision is to electrify life in one generation. Underpinning OPG's strategic objectives are the Company's commitments in the areas of climate change action, workplace equity, diversity and inclusion (ED&I), and Indigenous reconciliation. The four business imperatives represent the areas in which OPG aims to demonstrate excellence to enable the achievement of its strategic objectives. OPG integrates environmental, social and governance (ESG) principles throughout its corporate strategy and employs ESG considerations in its business conduct and decision-making.



Reporting Structure

The composition of OPG's reportable business segments effective as at December 31, 2024 was as follows:

- Regulated – Nuclear Generation;
- Regulated – Nuclear Sustainability Services;
- Regulated – Hydroelectric Generation;
- Contracted Hydroelectric and Other Generation; and
- Atura Power.

OPG earns regulated prices for electricity generated from most of its Ontario-based hydroelectric facilities and all of the nuclear facilities that it operates (collectively, prescribed facilities or regulated facilities). These Ontario-based regulated facilities comprise 54 hydroelectric generating stations across several major river systems in the province, the Pickering nuclear GS (Pickering GS) and the Darlington nuclear GS (Darlington GS). The operating results related to these facilities are described in the Regulated – Hydroelectric Generation and Regulated – Nuclear Generation business segments. Any small modular reactors (SMRs) at the Darlington New Nuclear project (DNNP) site are also prescribed as regulated facilities by the OEB, and the expenditures related to the development of SMRs are included in the Regulated – Nuclear Generation business segment.

The Regulated – Nuclear Sustainability Services business segment reports the results of the Company's operations associated with the management of used nuclear fuel and low and intermediate level irradiated materials (referred to as low and intermediate level waste or L&ILW), the decommissioning of OPG's nuclear generating facilities, the management of nuclear fixed asset removal and nuclear waste management segregated funds (Nuclear Segregated Funds) and related activities including the inspection and maintenance of used nuclear fuel and L&ILW storage facilities.

OPG's non-regulated generating facilities reported in the Contracted Hydroelectric and Other Generation business segment include 12 hydroelectric generating stations, two thermal generating stations and one solar facility located in Ontario that are operated under ESAs with the IESO or other long-term contracts. Through Eagle Creek, the business segment also includes 85 wholly or jointly owned and operated hydroelectric generating stations located in the United States.

The Atura Power business segment reports the results of Atura Power's operations, which include a fleet of combined cycle plants in Ontario. The fleet comprises the Napanee GS, the Halton Hills GS, the Portlands Energy Centre and the Brighton Beach GS. The facilities operate under ESAs with the IESO. Additionally, the segment includes Atura Power's expenditures on business development projects, including low-carbon hydrogen production, battery energy storage systems and combined cycle plant expansion.

A detailed description of OPG's business segments is provided in the section, *Business Segments*.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as at December 31 was as follows:

(MW)	**2024**	**2023**
Regulated – Nuclear Generation [1]	**4,698**	4,850
Regulated – Hydroelectric Generation	**6,566**	6,566
Contracted Hydroelectric and Other Generation [2]	**4,080**	4,105
Atura Power	**2,715**	2,715
Total [3]	**18,059**	18,236

[1] The in-service generating capacity as at December 31, 2024 excludes Unit 4 of the Darlington GS, and as at December 31, 2023, excludes Unit 1 and Unit 4 of the Darlington GS. Unit 4 was taken offline for refurbishment in July 2023. Unit 1 was taken offline for refurbishment in February 2022 and returned to service in November 2024. Unit 4 and Unit 1 each have a generating capacity of 878 MW. Additionally, as planned, Unit 1 and Unit 4 of the Pickering GS, each with a generating capacity of 515 MW, ceased commercial operation and were permanently taken offline on October 1, 2024 and December 31, 2024, respectively. As at December 31, 2024, the Darlington GS had three units in service and the Pickering GS had four units in service.

[2] Includes OPG's proportionate share of in-service generating capacity from co-owned and minority shareholdings in electricity generating facilities.

[3] In-service generating capacity represents the portion of installed capacity (the highest level of MW output which a generating unit can maintain indefinitely under reference conditions, without damage to the unit) that has not been removed from service.

The total in-service generating capacity as at December 31, 2024 decreased by 177 MW compared to 2023. The decrease was primarily due to Unit 1 and Unit 4 of the Pickering GS ceasing commercial operation and being permanently taken offline on October 1, 2024, and December 31, 2024, respectively, as planned. The decrease was partially offset by the return to service of Unit 1 of the Darlington GS following refurbishment on November 27, 2024. Additionally, the decrease was also due to a reduction in the Atikokan GS contractual capacity by 25 MW, reflecting the low-pressure turbine derate.

REVENUE MECHANISMS FOR REGULATED AND NON-REGULATED GENERATION

Regulated Generation

The majority of OPG's electricity generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric Generation business segments. The OEB sets volumetric prices for electricity generated from these Ontario-based nuclear and regulated hydroelectric facilities. The regulated prices are generally designed to permit the Company to recover, over a forecasted generation volume, an allowed level of operating costs and capital investment and to earn a formula-based rate of return on a deemed equity portion (ROE) of the capital invested in the regulated assets, known as rate base. Rate base for OPG represents the average net level of investment in regulated fixed and intangible assets in service and an allowance for working capital. *Ontario Regulation 53/05* under the *Ontario Energy Board Act, 1998* sets out certain requirements the OEB must follow in setting regulated prices for OPG's prescribed facilities. The outcomes of OPG's applications for regulated prices to the OEB determine a large portion of the Company's revenues and can have a significant impact on the Company's financial performance.

The following table presents the OEB-authorized regulated prices for electricity generated from the regulated facilities in Ontario for the period from January 1, 2023 to December 31, 2026 in effect as of the date of this MD&A:

($/MWh)	**2023**	**2024**	**2025**	**2026**
Regulated – Nuclear Generation				
Base regulated price [1]	107.79	**103.48**	102.85	111.33
Deferral and variance account rate riders [2]	1.25	**4.28**	8.76	12.43
Total regulated price	109.04	**107.76**	111.61	123.76
Regulated – Hydroelectric Generation				
Base regulated price	43.88	**43.88**	43.88	43.88
Deferral and variance account rate riders [2]	1.03	**3.64**	3.30	3.30
Total regulated price	44.91	**47.52**	47.18	47.18

[1] Base regulated prices for the nuclear facilities were established using a rate smoothing approach that defers a portion of approved annual nuclear revenue requirements for future collection in the Rate Smoothing Deferral Account. Base regulated prices for the nuclear facilities do not include amounts deferred in the Rate Smoothing Deferral Account.

[2] Deferral and variance account riders reflect the OEB's January 2022 payment amounts order that authorized recovery and repayment of balances recorded in regulatory deferral and variance accounts as at December 31, 2019, and, effective July 2024, the OEB's June 2024 decision and order that authorized recovery and repayment of balances recorded in regulatory deferral and variance accounts as at December 31, 2022.

Base Regulated Prices

The base regulated prices in effect beginning January 1, 2022 were established by the payment amounts order issued by the OEB in January 2022, reflecting the OEB's decisions on OPG's 2022-2026 application for new regulated prices issued during the second half of 2021. These decisions included approval of a proposed settlement between OPG and intervenors on most of the issues in the application (2021 Settlement Agreement). The regulated prices for the 2022-2026 period support the remainder of the Darlington Refurbishment project, the continued operation of the Pickering GS to the then-planned shutdown dates, and the ongoing operation of the regulated hydroelectric facilities. The OEB's decisions on the application also support the advancement of SMRs at the DNNP site.

The approved regulated prices for the 2022-2026 period were set on the assumption of the continued operation of Units 5 to 8 of the Pickering GS until the end of 2025. Subsequent to the issuance of the January 2022 payment amounts order, in September 2022, the Province announced its support for the continued safe operation of Units 5 to 8 of the Pickering GS until the end of September 2026 and, in December 2022, amended *Ontario Regulation 53/05* to require OPG to establish a variance account to record the additional revenues and costs associated with operating these units between January 1, 2026 and September 30, 2026. The disposition of the account balance will be subject to the OEB's review in a future proceeding. On January 28, 2025, the Province released a proposal for potential amendments to *Ontario Regulation 53/05* intended to clarify the scope of the variance account to ensure that

OPG can record costs incurred beginning in 2024 to retain the capacity and readiness to operate Units 5 to 8 of the Pickering GS upon refurbishment, subject to the requisite approvals. The comment period for the proposal ends on March 14, 2025. Further details on OPG's plan for continued operation of the Pickering GS can be found in the section, *Significant Developments* under the heading, *Project Excellence – Pickering Refurbishment* and *Core Business and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability*.

Nuclear Base Regulated Prices

The base regulated prices for OPG's nuclear electricity generation (nuclear base regulated price) beginning on June 1, 2017 have been set using a rate smoothing approach that defers a portion of approved annual nuclear revenue requirements for future collection in the Rate Smoothing Deferral Account, with the objective of making more stable changes in OPG's overall production-weighted regulated price year over year during the Darlington Refurbishment project period, consistent with the requirements of *Ontario Regulation 53/05*. The approved nuclear revenue requirement for each year is based on the OEB-allowed level of operating costs and a return of and on rate base, as reduced by a stretch factor amount under the custom incentive regulation framework for the nuclear facilities. In accordance with *Ontario Regulation 53/05*, the nuclear revenue requirement is adjusted by the amount of OPG's revenues, net of costs, from leasing the Bruce nuclear generating stations to Bruce Power, such that OPG's revenues reduce the nuclear revenue requirement and OPG's costs increase it.

Pursuant to the OEB's January 2022 payment amounts order, $64 million of the approved nuclear revenue requirement was deferred in 2023 and none was deferred in 2024 in the Rate Smoothing Deferral Account. No portion of the nuclear revenue requirements will be deferred over the 2025-2026 period. Amounts deferred in the Rate Smoothing Deferral Account are recorded as revenue in the Regulated – Nuclear Generation business segment in the period to which the underlying approved revenue requirement relates. *Ontario Regulation 53/05* requires the OEB to authorize recovery of the deferred amounts, together with interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, over a period not to exceed ten years following the end of the Darlington Refurbishment project.

Hydroelectric Base Regulated Prices

Pursuant to *Ontario Regulation 53/05*, the base regulated price for OPG's regulated hydroelectric electricity generation (hydroelectric base regulated price) for the period from January 1, 2022 to December 31, 2026 has been set equal to the 2021 hydroelectric base regulated price.

Deferral and Variance Account Rate Riders

Regulatory deferral and variance accounts (regulatory accounts) are typically established by the OEB to capture, for subsequent review and approval, differences between actual costs and revenues and the corresponding forecast amounts approved by the OEB in setting base regulated prices, or to record the impact of items not reflected in the approved base regulated prices. Such accounts generally help to mitigate risks and uncertainties to the regulated entity and its customers. Certain of OPG's regulatory accounts are established as required by *Ontario Regulation 53/05*. Revenue received, or reduced, from the recovery, or repayment, of regulatory account balances is largely offset by the amortization expense of the associated regulatory assets and regulatory liabilities recorded on the consolidated balance sheet. Descriptions of OPG's regulatory accounts can be found in Note 7 of OPG's 2024 audited consolidated financial statements.

The OEB's January 2022 payment amounts order on OPG's 2022-2026 application for new regulated prices approved new rate riders on nuclear and regulated hydroelectric electricity generation, effective January 1, 2022, to recover and repay regulatory account balances as at December 31, 2019.

In December 2023, OPG filed an application with the OEB requesting disposition of regulatory account balances as at December 31, 2022, less amounts previously approved for recovery or repayment of the regulatory account balances. In June 2024, the OEB issued a decision and order approving a proposed complete settlement on the application reached by OPG and intervenors (2024 Settlement Agreement), with resulting incremental rate riders on nuclear and regulated hydroelectric electricity generation effective July 1, 2024. The 2024 Settlement Agreement is discussed further in the section, *Significant Developments* under the heading, *Financial Strength – OPG's Application with the OEB for Disposition of Deferral and Variance Accounts*.

Non-Regulated Generation

All of OPG's non-regulated generating assets in Ontario are subject to ESAs with the IESO. As of December 31, 2024, the contracts for Ontario-based generating assets had the following expiration dates:

Generating Facility	Generation Type	Term	Contract Expiry Date
Brighton Beach GS [1]	Natural Gas	10 years	July 2034
Atikokan GS [2]	Biomass	5 years	July 2029
Lennox GS	Oil or Natural Gas	7 years	April 2029
Portlands Energy Centre [3]	Natural Gas	20 years	April 2029
Halton Hills GS	Natural Gas	25 years	April 2035
Nanticoke solar facility	Solar	20 years	March 2039
Napanee GS	Natural Gas	20 years	March 2040
Lac Seul and Ear Falls generating stations	Hydroelectric	50 years	February 2059
Healey Falls GS	Hydroelectric	50 years	April 2060
Sandy Falls, Wawaitin, Lower Sturgeon and Hound Chute generating stations	Hydroelectric	50 years	December 2060
Little Long, Harmon, Smoky Falls and Kipling generating stations [4]	Hydroelectric	50 years	January 2064
Peter Sutherland Sr. GS	Hydroelectric	50 years	March 2067

[1] The facility operated under an energy conversion agreement with Shell Energy North America (Canada) Inc. until July 15, 2024. Effective July 16, 2024, the facility operates under a new ESA with the IESO for a term of 10 years.

[2] In September 2024, OPG and the IESO entered into an amended and restated ESA for the Atikokan GS, extending the contract expiry to July 2029.

[3] The ESA includes an option for Atura Power or the IESO to exercise, in 2028, an extension of the contract expiry by five years under certain conditions.

[4] These facilities are also known as the Lower Mattagami generating stations.

The majority of the generating assets located in the US, and owned by Eagle Creek, earn revenue through the supply of energy and capacity into wholesale electricity markets, with a number of the generating facilities earning revenue under energy and capacity contracts, with expiry dates ranging from 2025 to 2043.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's operating results for the years ended December 31, 2024 and December 31, 2023. A discussion of OPG's performance by business segment can be found in the section, *Discussion of Operating Results by Business Segment*.

(millions of dollars – except where noted)	**2024**	**2023**
Revenue	**7,187**	7,434
Fuel expense	**1,049**	974
Operations, maintenance and administration expenses	**3,318**	3,136
Depreciation and amortization expenses	**1,270**	1,071
Accretion on fixed asset removal and nuclear waste management liabilities	**1,221**	1,178
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(1,102)**	(1,057)
Other net expenses (gains)	**69**	(66)
Earnings before interest and income taxes	**1,362**	2,198
Net interest expense	**186**	103
Income tax expense	**170**	336
Net income	**1,006**	1,759
Net income attributable to the Shareholder	**988**	1,741
Net income attributable to non-controlling interest [1]	**18**	18
Electricity generation (TWh) [2]	**82.1**	80.9
Cash flow provided by operating activities	**2,211**	2,538
Capital expenditures [3]	**3,725**	2,829
Earnings (loss) before interest and income taxes by segment		
Regulated – Nuclear Generation	**337**	1,046
Regulated – Hydroelectric Generation	**584**	576
Contracted Hydroelectric and Other Generation	**242**	288
Atura Power	**276**	356
Total electricity generating business segments	**1,439**	2,266
Regulated – Nuclear Sustainability Services	**(108)**	(110)
Other	**31**	42
Earnings before interest and income taxes	**1,362**	2,198

[1] Relates to the following: 25 percent interest of Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in Lower Mattagami Limited Partnership; 33 percent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in PSS Generating Station Limited Partnership; 15 percent interest and 5 percent interest of corporations wholly owned by Six Nations of Grand River Development Corporation and the Mississaugas of the Credit First Nation, respectively, in Nanticoke Solar LP; and non-controlling interests in certain electricity generating facilities in the United States.

[2] Includes OPG's proportionate share of electricity generation from co-owned and minority-held facilities.

[3] Includes net changes in accruals; excludes the acquisition of the new corporate headquarters building and surrounding lands at 1908 Colonel Sam Drive in Oshawa, Ontario in February 2023.

Net income attributable to the Shareholder was $988 million for 2024, representing a decrease of $753 million compared to 2023. Earnings before interest and income taxes were $1,362 million for 2024, representing a decrease of $836 million compared to 2023.

Significant factors that decreased earnings before interest and income taxes (EBIT):

- Net decrease in revenue of $470 million from the Regulated – Nuclear Generation business segment, as a result of lower electricity generation of 3.1 terawatt hours (TWh) and a lower nuclear base regulated price in effect during 2024. The lower electricity generation was expected and primarily due to higher planned outage days at the Darlington GS from a planned cyclical maintenance outage on the station's Unit 2 in the first half of 2024 and the cessation of commercial operation of Unit 1 of the Pickering GS on October 1, 2024, partially offset by fewer planned outage days at the Pickering GS. An increase in revenue reflecting the impact of the new rate riders for disposition of regulatory accounts under the OEB's June 2024 decision and order approving the 2024 Settlement Agreement, effective July 1, 2024, was largely offset by a corresponding increase in the amortization expense of regulatory assets and regulatory liabilities recorded for regulatory account balances;

- Higher depreciation and amortization expenses of $101 million from the Regulated – Nuclear Generation business segment, excluding amortization expense related to the recovery and repayment of OEB-authorized regulatory account balances, primarily due to higher depreciation expense recognized from placing capital in service, including the return to service of Unit 3 and Unit 1 of the Darlington GS following refurbishment in July 2023 and November 2024, respectively, and lower amounts of depreciation expense recorded as recoverable from customers through regulatory accounts;

- Higher OM&A expenses of $64 million from the Regulated – Nuclear Generation business segment, largely due to expected higher expenditures related to the cyclical maintenance activities and other planned maintenance work executed as a result of higher planned outage days at the Darlington GS, partially offset by lower expenses due to fewer planned outage days at the Pickering GS. Increased compensation expenses recognized in the fourth quarter of 2024 as a result of the ratification of a three-year renewal collective agreement between the Power Workers' Union (PWU) and OPG in November 2024 were offset by the higher compensation expenses recognized in the second quarter of 2023 related to the impact on OPG's collective agreements of the Ontario Superior Court's decision that found unconstitutional provincial legislation that set limits on compensation increases for employees in the Ontario public sector (Bill 124 Court Decision) and the OEB's subsequent decisions issued in 2023 that denied OPG's request for a regulatory account to record these cost impacts. The renewal collective agreement with the PWU reached in 2024 is discussed further in the section, *Significant Developments* under the heading, *Financial Strength – Power Workers' Union Collective Agreement* and the Bill 124 Court Decision is discussed further in the section, *Core Business and Outlook* under the heading, *Financial Strength – Ontario Court Bill 124 Decision*; and

- Lower other net gains of $135 million, primarily due to the release of a previously recognized contingent liability in the fourth quarter of 2023 under a 2021 settlement agreement related to an acquisition of combined cycle plants, a gain recognized in the second quarter of 2023 related to the sale of certain premises located at 800 Kipling Avenue in Toronto, Ontario in October 2022, and a loss recorded in the second quarter of 2024 in connection with the OEB's decision and order approving the 2024 Settlement Agreement.

Net interest expense increased by $83 million in 2024, compared to 2023, primarily due to a higher amount of interest recorded as recoverable from customers through regulatory accounts in 2023 and higher interest on the Company's long-term debt due to bond issuances during 2024.

Income tax expense decreased by $166 million in 2024, compared to 2023. The decrease was primarily due to the impact of lower earnings before income taxes in 2024 and certain tax adjustments recorded in 2023.

Electricity Generation

Electricity generation for the years ended December 31 was as follows:

(TWh)	**2024**	**2023**
Regulated – Nuclear Generation	**33.0**	36.1
Regulated – Hydroelectric Generation	**32.5**	31.4
Contracted Hydroelectric and Other Generation [1]	**5.0**	5.2
Atura Power	**11.6**	8.2
Total OPG electricity generation	**82.1**	80.9

[1] Includes OPG's proportionate share of electricity generation from co-owned and minority shareholdings in electricity generating facilities.

Total OPG electricity generation increased by 1.2 TWh in 2024, compared to 2023, primarily due to higher electricity generation from the Atura Power and the Regulated – Hydroelectric Generation business segments, partially offset by lower electricity generation from the Regulated – Nuclear Generation business segment.

Electricity generation from the Regulated – Nuclear Generation business segment decreased by 3.1 TWh in 2024, compared to 2023. The decrease was primarily due to higher planned and unplanned outage days at the Darlington GS and the cessation of commercial operation of Unit 1 of the Pickering GS on October 1, 2024, partially offset by fewer planned outage days at the Pickering GS. Unit 4 of the Pickering GS ceased commercial operation and was permanently taken offline on December 31, 2024.

The increase in electricity generation of 1.1 TWh from the Regulated – Hydroelectric Generation business segment in 2024, compared to 2023, was mainly due to higher electricity generation at the hydroelectric facilities in the Niagara region as a result of less production forgone due to SBG conditions reflecting higher electricity demand, and higher water flows across most of Ontario.

Electricity generation from the Contracted Hydroelectric and Other Generation business segment in 2024 was comparable to 2023.

Electricity generation from the Atura Power business segment increased by 3.4 TWh in 2024, compared to 2023, primarily due to higher demand for electricity generation from the combined cycle plants.

Ontario's electricity demand as reported by the IESO was 140.4 TWh in 2024, compared to 137.1 TWh in 2023, excluding electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric and certain nuclear generating stations, and other grid-connected renewable resources. Baseload generation surplus in Ontario was lower in 2024, compared to 2023. Production forgone at OPG's regulated hydroelectric stations due to SBG conditions was 0.4 TWh in 2024 and 1.0 TWh in 2023. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions was offset by the impact of a regulatory account authorized by the OEB. OPG did not forgo any electricity production at its nuclear generating stations due to SBG conditions.

Cash Flow from Operations

Cash flow provided by operating activities during 2024 was $2,211 million, compared to $2,538 million for 2023. The decrease was primarily due to lower revenue receipts from the Regulated – Nuclear Generation business segment and higher OM&A expenditures, largely offset by lower income tax installment payments and higher revenue receipts from the Regulated – Hydroelectric Generation business segment.

Capital Expenditures

Capital expenditures for the years ended December 31 were as follows:

(millions of dollars)	**2024**	**2023**
Regulated – Nuclear Generation – Darlington Refurbishment Project	**988**	974
Regulated – Nuclear Generation – Pickering Refurbishment and DNNP	**943**	251
Regulated – Nuclear Generation – Excluding Darlington Refurbishment Project, Pickering Refurbishment Project and DNNP	**604**	634
Regulated – Hydroelectric Generation	**434**	370
Contracted Hydroelectric and Other Generation	**220**	313
Atura Power	**382**	148
Other [1]	**154**	139
Total capital expenditures [2]	**3,725**	2,829

[1] Excludes the acquisition of the new corporate headquarters building and surrounding lands at 1908 Colonel Sam Drive in Oshawa, Ontario in February 2023.
[2] Includes net changes in accruals.

Total capital expenditures increased by $896 million in 2024, compared to 2023, primarily due to higher expenditures for the Regulated – Nuclear Generation business segment.

Capital expenditures for the Darlington Refurbishment project in 2024 were comparable to 2023.

Capital expenditures for the Pickering Refurbishment project and DNNP increased by $692 million in 2024, compared to 2023. The increase was due to expenditures on pre-execution phase refurbishment activities for Units 5 to 8 of the Pickering GS and higher expenditures for site preparation, procurement and other ongoing development activities for SMRs at the DNNP site. Further details on the continued operation plan for the Pickering GS and the DNNP can be found in the section, *Significant Developments* under the headings, *Project Excellence – Pickering Refurbishment* and *Project Excellence – Darlington New Nuclear Project,* respectively.

Excluding the Darlington Refurbishment project, Pickering Refurbishment project and DNNP, capital expenditures for the Regulated – Nuclear Generation business segment decreased by $30 million in 2024, compared to 2023. The decrease was mainly due to lower expenditures for the replacement of primary moisture separators, a component of steam generators, at the Darlington GS. Further details on the primary moisture separators at the Darlington GS can be found in the section, *Core Business and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability*.

Capital expenditures for the Regulated – Hydroelectric Generation business segment increased by $64 million in 2024, compared to 2023. The increase was primarily due to higher expenditures on redevelopments of hydroelectric generating stations as well as the ongoing refurbishment program and concrete rehabilitation work across the hydroelectric fleet.

Capital expenditures for the Contracted Hydroelectric and Other Generation business segment decreased by $93 million in 2024, compared to 2023. The decrease was primarily due to lower expenditures on the Little Long Dam Safety project, with all gates placed in service in the third quarter of 2023, and lower expenditures on the Smoky Falls Dam Safety project, with the two new sluicegates placed in service in the first quarter of 2024.

Capital expenditures for the Atura Power business segment increased by $234 million in 2024, compared to 2023. The increase was primarily due to higher expenditures for overhaul activities at existing combined cycle plant facilities, expenditures for the expansion of the combined cycle plant at the Napanee GS under a long-term agreement with the IESO executed in June 2024, higher expenditures on the development of a battery energy storage system at the Napanee GS site (Napanee BESS) under a long-term agreement with the IESO executed in 2023, and higher expenditures for the advancement of the Niagara Hydrogen Centre (NHC), a low-carbon hydrogen development

project. Further details on the project to expand the combined cycle plant at the Napanee GS can be found in the section, *Significant Developments* under the heading, *Napanee Combined Cycle Generating Station Expansion*.

Capital expenditures for the Other category in 2024 were comparable to 2023.

Further details on the Company's major projects can be found in the section, *Core Business and Outlook* under the heading, *Project Excellence.*

SIGNIFICANT DEVELOPMENTS

Project Excellence

Pickering Refurbishment

On January 23, 2025, the Province announced its approval of OPG's plan to proceed with the project definition phase as the next step toward refurbishing Units 5 to 8 of the Pickering GS. OPG Board of Directors' (Board) approved budget for this work is $4.1 billion, bringing the total Board-approved budget for the project to date to $6.2 billion. During the definition phase, OPG will complete a high-quality cost estimate and schedule for the project, progress detailed engineering, further procurement and contracting work, continue to optimize project scope, and develop the project execution plan. The definition phase is expected to last through 2026. In preparing for refurbishment, OPG has entered into a contract with CanAtom, a joint venture of Aecon Group Inc. and AtkinsRéalis, for early engineering and procurement in support of the re-tube feeder and boiler replacement program, which will represent a majority of the critical path execution schedule.

Once refurbished, the Pickering GS would continue to provide over 2,000 MW of baseload generating capacity, equivalent to powering approximately two million homes, to help meet Ontario's demand for electricity. The refurbishment is anticipated to be completed by the mid-2030s.

Further details on the continued operation plan for the Pickering GS can be found in the section, *Core Business and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability*.

Darlington Refurbishment

On November 27, 2024, following the successful completion of start-up activities, the refurbished Unit 1 of the Darlington GS was reconnected to the electricity grid, ahead of the original schedule. The return to service of Unit 1 represents another significant milestone in OPG's path toward ensuring that the four-unit Darlington GS can continue to provide at least another 30 years of cost effective, reliable and clean energy for Ontario. Unit 1 provides 878 MW of baseload electricity generating capacity in the province.

The Unit 4 refurbishment is executing the third major segment, Reassembly, which includes the installation and reassembly of reactor components. The installation of calandria tubes was successfully completed in January 2025, and the installation of fuel channels and lower feeders is in progress. Unit 4 is scheduled to be returned to service in 2026. The ongoing refurbishment of Unit 4 incorporates the benefits of experience with the completed refurbishments of Unit 2, Unit 3 and Unit 1, and additional strategic improvements.

The Darlington Refurbishment project is discussed further in the section, *Core Business and Outlook* under the heading, *Project Excellence*.

Darlington New Nuclear Project

OPG continues to advance the DNNP with the goal of deploying Canada's first grid-scale SMR by the end of the decade, using the BWRX-300 reactor plant technology. As announced by the Province in July 2023, OPG has also initiated planning and licensing for three additional SMRs at the DNNP site. Pending the Province and regulatory approvals for the construction of the units, the DNNP's total generating capacity is expected to reach approximately 1,200 MW. The projected in-service dates for the three additional SMRs are in the mid-2030s.

The DNNP is currently in the definition phase, which includes activities such as progressing detailed engineering, completing construction planning, procuring long-lead items and completing site preparation activities. In June 2024 and November 2024, respectively, the project completed the tunnel boring machine launch shaft retaining wall for the condenser cooling water system and the reactor building shaft retaining wall. Site preparation activities necessary for the start of construction for the first SMR have been substantially completed. OPG is continuing to progress planning and procurement of long-lead items such as the fabrication of the reactor pressure vessel (RPV). The RPV is the core of a nuclear generating station design, acting as the primary pressure vessel and integrated steam generator providing natural circulation for safe and efficient electricity generation.

OPG's DNNP site preparation licence approved by the CNSC expires in October 2031. In October 2022, OPG submitted the Licence to Construct application to the CNSC for the first SMR at the DNNP site. The first CNSC public hearing took place in January 2024, with the focus on the applicability of the DNNP environmental assessment (EA) to the BWRX-300 technology. In April 2024, the CNSC announced its decision that the existing EA for the DNNP is applicable to the BWRX-300 technology. The CNSC held the two-part second public hearing to consider OPG's Licence to Construct application in October 2024 and January 2025, with the CNSC's decision on the application currently pending.

Redevelopment of Hydroelectric Generating Stations

OPG has commenced the execution of three projects to redevelop existing hydroelectric generating stations in Ontario that are approaching the end of their operational lives. The redevelopments will generally involve construction of new powerhouses or powerhouse extensions, replacement of turbine and generator units and supporting systems, and replacement or rehabilitation of other structures at the stations. The redevelopments are expected to ensure continued safe and reliable operations of the assets for approximately an additional 80 to 90 years.

In November 2024, OPG initiated the execution phase of a project to redevelop the Kakabeka Falls GS, the second oldest generating station in OPG's Ontario-based hydroelectric fleet, located along the Kaministiquia River in northwestern Ontario. The project will involve construction of a new powerhouse extension, replacement of the surge system, and replacement of the penstocks. The redeveloped station is expected to have a generating capacity of approximately 27 MW. The project's expected in-service date is 2028, with an approved budget of $519 million.

During the fourth quarter of 2024, OPG initiated the execution phase of a project to redevelop the Coniston and Stinson hydroelectric generating stations, located along the Wanapitei River east of Sudbury, Ontario. The redeveloped stations are expected to have a combined generating capacity of approximately 12 MW. The project's expected in-service date is 2027, with a combined approved budget of $178 million.

The above hydroelectric generating stations are reported in the Regulated – Hydroelectric Generation business segment.

Napanee Combined Cycle Generating Station Expansion

In June 2024, Atura Power entered a long-term agreement with the IESO for the expansion of the combined cycle plant at the Napanee GS. The project will add an additional combustion turbine generator unit at the Napanee GS site, providing up to 405 MW of electricity output to Ontario's electricity grid. The project was selected through the IESO's long-term procurement process, which sought 918 MW of non-storage capacity to support the province's growing electricity system needs. Engineering, design and permitting activities are progressing on schedule, with procurement of critical equipment completed. The construction is expected to commence in 2025, with the facility projected to be in service in 2028 under a 12-year capacity agreement. Atura Power's development projects are discussed further in the section, *Core Business and Outlook* under the heading, *Project Excellence – Atura Power Development Projects*.

Exploring Community Interest in New Electricity Generation Opportunities

In November 2024, the Province requested OPG to proceed with discussions with Indigenous and municipal leaders on its existing Ontario sites in Port Hope (Wesleyville site), Haldimand Country (Nanticoke site) and St. Clair Township (Lambton site) to determine interest in exploring new electricity generation opportunities, including nuclear energy generation. This followed the release of the Province's *Ontario's Affordable Energy Future: The Pressing Case for More Power* document and subsequent introduction of the *Affordable Energy Act, 2024* (Bill 214) in October 2024, which together outlined the Province's vision for meeting the increasing demand for energy in Ontario. Also in October 2024, the IESO announced an updated forecast showing that Ontario's electricity demand for energy would grow by 75 percent leading up to 2050, with annual consumption rising from 151 TWh in 2025 to 263 TWh in 2050. Early community engagement is a critical step to advancing any new electricity generation projects.

The Wesleyville site had previously undergone partial development for an electricity generation facility. The Nanticoke and Lambton sites formerly hosted OPG's coal-fired generating stations that have now been decommissioned. All three sites are zoned for electricity generation and have proximity to transmission infrastructure.

In January 2025, with First Nations' willingness to enter discussions and following a formal expression of interest from Town of Port Hope, the Province requested OPG to explore opportunities for new nuclear energy generation at the Wesleyville site. Based on OPG's early assessment, the Wesleyville site could host up to 10,000 MW of new nuclear energy generation, which could power the equivalent of approximately ten million homes. OPG will work with local communities and First Nations to determine their support for a potential project as part of the exploration process.

Operational Excellence

Refurbishment of Hydroelectric Generating Stations

OPG has announced and is progressing the execution of refurbishment projects across multiple hydroelectric generating stations in Ontario, ensuring their continued reliable operations to deliver decades of renewable electricity and help meet the province's energy needs.

In April 2024, OPG announced a refurbishment project at the Sir Adam Beck generating complex along the Niagara River. The project involves the refurbishment of up to 25 generating units and is expected to increase the generating capacity of the existing stations by approximately 50 MW, ensuring the continued delivery of up to 1,700 MW of electricity. The refurbishment work is expected to continue over the next 15 years.

In May 2024, OPG announced it is advancing the refurbishment of R.H. Saunders GS, located on the St. Lawrence River. The project involves the refurbishment of 16 generating units, ensuring the continued delivery of up to 1,045 MW of electricity. The refurbishment work is expected to continue over the next 16 years.

In June 2024, OPG announced the refurbishment of eight hydroelectric generating stations located on the Madawaska River and the Ottawa River in Eastern Ontario. The work involves the refurbishment of 45 generating units, ensuring the continued delivery of up to approximately 1,600 MW of electricity. The refurbishment work is expected to continue over the next 20 years.

In January 2025, the Province announced its support to OPG's plan to refurbish and expand a number of hydroelectric generating stations in Northern Ontario. The work will ensure the continued delivery of up to 830 MW of electricity. The projects are expected to continue over the next ten years.

All of the above generating stations are reported in the Regulated – Hydroelectric Generation business segment.

Power Workers' Union Collective Agreement

The governing two-year collective agreement between the PWU and OPG expired on March 31, 2024. On November 20, 2024, the PWU membership ratified a three-year renewal collective agreement negotiated by the parties, covering the period from April 1, 2024 to March 31, 2027. The collective agreement provides for annual wage increases beginning April 1, 2024, and a lump sum payment to active employees effective November 20, 2024, and includes impacts arising in connection with the Bill 124 Court Decision. In 2023, the OEB denied OPG's request for a regulatory account to record compensation cost impacts attributable to the nuclear facilities as a result of the Bill 124 Court Decision. For the year ended December 31, 2024, OPG recognized compensation expenses of $90 million resulting from the ratification of the renewal collective agreement with the PWU.

For further details on the Company's collective agreements, refer to the section, *Liquidity and Capital Resources* under the heading, *Contractual Obligations – Collective Agreements.* The Bill 124 Court Decision is discussed further in the section, *Core Business and Outlook* under the heading, *Financial Strength – Ontario Court Bill 124 Decision.*

Financial Strength

OPG's Application with the OEB for Disposition of Deferral and Variance Accounts

In December 2023, OPG filed an application with the OEB requesting disposition of regulatory account balances as at December 31, 2022, less amounts previously approved for recovery or repayment of the regulatory account balances as of December 31, 2019, through incremental rate riders on nuclear and regulated hydroelectric electricity generation. The application also addressed the anticipated impacts from the Market Renew Program, an IESO initiative to redesign Ontario's electricity markets, on OPG's regulated facilities.

In the second quarter of 2024, OPG and intervenors in the proceeding reached a proposed complete settlement on OPG's application. On June 13, 2024, the OEB issued a decision and order approving the 2024 Settlement Agreement, providing for the recovery of a net total of $481 million in connection with amounts recorded in OPG's regulatory accounts and associated income tax impacts, which represented a reduction of $22 million from the amounts sought in OPG's application. This included the resolution of the parties' positions with respect to whether any of the net proceeds from OPG sale of certain premises at 800 Kipling Avenue in Toronto, Ontario received in 2022 should be credited to ratepayers. The balances agreed by the parties are being recovered or repaid effective July 1, 2024 over a period of 30 months. The associated income tax impacts included for recovery were previously recorded as part of the regulatory asset for deferred income taxes. The 2024 Settlement Agreement also provides for regulatory mechanisms to address the anticipated impacts from the IESO's Market Renewal Program on OPG's regulated facilities until the effective date of base regulated prices arising from OPG's next application with the OEB, as part of which any of the parties may take a different position on such mechanisms on a prospective basis. In the second quarter of 2024, the Company recorded a loss of $25 million in connection with the OEB's decision and order on the 2024 Settlement Agreement. Revenue received from the recovery of regulatory account balances is largely offset by amortization expense of regulatory assets and regulatory liabilities recorded for these balances.

Further details on the Market Renewal Program can be found in the section, *Risk Management* under the heading, *Risks to Maintaining Financial Strength – Electricity Markets*.

Green Bonds

On June 7, 2024, OPG's wholly-owned Lower Mattagami Energy Limited Partnership (LME) completed a private placement bond offering with the issuance of $200 million of green bonds, maturing in June 2054, with a coupon interest rate of 4.69 percent. The net proceeds were used to refinance LME debt maturities in June 2024.

In June 2024, OPG released its Sustainable Finance Framework, which replaced OPG's Green Bond framework and includes a broader array of eligible projects and programs such as SMRs, large new nuclear projects, low-carbon hydrogen, battery energy storage and social projects, in recognition of the demand for clean electricity and OPG's commitment to advancing economic Reconciliation with Indigenous Nations and communities.

On June 28, 2024, OPG issued $1 billion of green bonds under its Sustainable Finance Framework, through its Medium Term Note Program. The issuance consisted of $500 million of senior notes maturing in June 2034, with a coupon interest rate of 4.83 percent, and $500 million of senior notes maturing in June 2054, with a coupon interest rate of 4.99 percent.

On September 11, 2024, OPG re-opened the June 28, 2024 dual tranche bond issuances under its Medium Term Note Program for an additional $300 million. The additional green bond issuance consisted of $200 million of senior notes maturing in June 2034, with a coupon interest rate of 4.83 percent, and $100 million of senior notes maturing in June 2054, with a coupon interest rate of 4.99 percent. The net proceeds from the above issuances were used to finance or re-finance Eligible Green Projects as defined under the Sustainable Finance Framework.

Acquisition of Lightstar Renewables LLC and Lightstar Operations One LLC

On January 31, 2024, OPG, under Eagle Creek, acquired 100 percent of the equity in Lightstar Renewables LLC and Lightstar Operations One LLC (collectively, Lightstar). Lightstar engages in the business of development, construction and operation of community solar generation projects in the United States, and is included in the Contracted Hydroelectric and Other Generation business segment. Total purchase consideration was $163 million (US$121 million). The identifiable assets acquired, with a fair value of $125 million, mainly comprised construction-in-progress property, plant and equipment and intangible assets pertaining to solar development projects.

President and CEO Announcement

In November 2024, OPG's Board announced Ken Hartwick's decision to retire as President and Chief Executive Officer (CEO) at the end of 2024 after nearly nine years with the Company. In line with OPG's leadership succession plan, the Board appointed Nicolle Butcher as President and CEO effective January 1, 2025. The appointment of Nicolle Butcher reflects the Company's commitment to strong leadership and strategic succession planning. With more than 25 years at OPG, Nicolle Butcher brings significant experience in managing one of North America's largest and most diverse electricity generating fleets, having most recently served as the Company's Chief Operations Officer, alongside her expertise in corporate business growth and development, and commercial business functions. The handover of responsibilities from Ken Hartwick to Nicolle Butcher was undertaken in line with a plan in place to ensure a seamless transition.

CORE BUSINESS AND OUTLOOK



Operational Excellence

Operational excellence at OPG is demonstrated through the safe, reliable and cost-effective generation of electricity from the Company's assets, by a highly trained and engaged workforce. Workplace health and safety and public safety are overriding priorities in all activities performed at OPG.

Electricity Generation Production and Reliability

Key strategic initiatives and developments in support of operational excellence, specific to each of OPG's core generating operations, are discussed below. Generation and reliability performance for 2024 is discussed by business segment in the section, *Discussion of Operating Results by Business Segment*.

Nuclear Operations

OPG is pursuing initiatives aimed at maximizing the safe and reliable operating life of the Pickering GS and targeting sustained high levels of performance at the Darlington GS over its post-refurbishment life. OPG is also focused on increasing electricity generation output from these nuclear generating stations by continuing to improve plant reliability and optimizing the planning and execution of outage and project work. OPG seeks to prioritize and optimize maintenance and project activities across the nuclear generating fleet by leveraging advancements in monitoring and diagnostic tools to enhance asset condition assessments. Establishing challenging performance targets based on comprehensive benchmarking and taking into account the operating environment of the stations continues to be a vital part of OPG's strategy to support these goals and ensure consistently strong financial performance of the Regulated – Nuclear Generation business segment.

The CNSC issues an annual report on the regulatory oversight and safety performance for nuclear power generating sites. The report assesses how well licensees are meeting regulatory requirements and program expectations in areas such as human performance, radiation and environmental protection, and emergency management and fire protection at Canada's nuclear power plants and waste management facilities. The most recent annual report, for the 2023 year, was issued by the CNSC in the fourth quarter of 2024. In the CNSC's 2023 report on OPG's nuclear safety performance, CNSC staff determined that all 14 Safety and Control Areas for the Darlington GS, Pickering GS, and the Darlington, Pickering and Western waste management facilities met CNSC staff's expectations.

On June 6, 2023, the Federal Court of Canada (Federal Court) endorsed the CNSC's move to require pre-placement and random alcohol and drug testing of workers in safety-critical positions, as mandated by the CNSC's approved regulatory document *REGDOC 2.2.4 – Fitness for Duty, Vol. II: Managing Alcohol and Drug Use* (version 3) (REGDOC 2.2.4) for use at Canadian high-security nuclear sites in November 2020. The requirements outlined in REGDOC 2.2.4 ensure that Canada is in line with the international best practices for the operation of high-security nuclear facilities. On July 11, 2023, the PWU and the Society of United Professionals (Society) filed a motion to appeal the Federal Court's June 6, 2023 decision, and a motion to stay the implementation of the pre-placement and random alcohol and drug testing regimes, pending the outcome of the appeal. On October 27, 2023, the stay motion was granted, and all licensees were restricted from implementing such testing pending the final disposition of the appeal, which was heard in January 2024. On November 6, 2024, the Federal Court of Appeal upheld the Federal Court's June 6, 2023 ruling. The unions are seeking leave to appeal the matter to the Supreme Court of Canada.

Pickering GS

OPG's plan to optimize the end of operations dates for the Pickering GS includes operating Units 5 to 8 until the end of September 2026, prior to the planned refurbishment, subject to the requisite approvals. In June 2023, OPG submitted an application to the CNSC to continue operations of Units 5 to 8 of the Pickering GS through 2026. In connection with this objective, OPG has continued to perform additional technical analysis and inspections to confirm fitness-for-service of fuel channels and other major station components in support of the station's planned end-of-life dates. Following a public hearing in June 2024, the CNSC announced in October 2024 its decision to amend the existing operating licence for the Pickering GS, authorizing the operation of Units 5 to 8 until the end of 2026.

As planned, Unit 1 and Unit 4 of the Pickering GS ceased commercial operation and were permanently taken offline on October 1, 2024 and December 31, 2024, respectively, after over 50 years of service. Following the end of commercial operation, Unit 1 and Unit 4 are being placed in a safe storage state under the existing operating licence for the Pickering GS. This involves defueling the reactors, removing all heavy water, and reconfiguring the station to isolate the units from the operating units. These activities must be conducted while meeting nuclear, radiological, industrial safety, and environmental protection standards. Defueling of the Unit 1 and Unit 4 reactors commenced on October 2, 2024 and January 5, 2025, respectively, and is continuing. Unit 2 and Unit 3 were previously permanently shut down and remain in a safe storage state. The costs associated with placing and subsequently monitoring units in a safe storage state are charged against the Nuclear Liabilities and reimbursed from the Nuclear Segregated Funds.

Following OPG's submission of a feasibility assessment as approved by the Board in August 2023, the Province announced its support for OPG proceeding with next steps toward refurbishing Units 5 to 8 of the Pickering GS in January 2024. As approved by the Board, OPG subsequently completed the project initiation phase, including certain preliminary engineering and securing certain long-lead components, in 2024. In January 2025, the Province announced its approval for OPG to proceed with the Board-approved project definition phase, which is expected to last through 2026. The Board-approved budget for the project initiation and definition activities is approximately $6.2 billion, which includes anticipated contractual commitments for future deliveries. Planning work is ongoing to determine which refurbishment activities for Units 5 to 8 could be conducted under the existing CNSC operating licence for the Pickering GS, valid until August 31, 2028. Licence amendments and renewals would be sought as required for the remainder of the refurbishment activities.

OPG continues to make strategic investments in the performance of Units 5 to 8 of the Pickering GS, with a focus on continuously improving equipment reliability and maximizing electricity generation output. This includes implementing equipment modifications and fuel handling reliability improvements, reducing equipment maintenance backlogs, and completing other critical and high priority work.

Darlington GS

OPG continues to make investments in the Darlington GS in order to ensure the station's ongoing safe and reliable operations and position it for industry-leading operating and cost performance in the longer term. In addition to completing the refurbishment of the station's generating units, this includes investments in life cycle and aging management projects, facility upgrades, and work in support of regulatory commitments. OPG continued to progress a number of such projects at the Darlington GS during 2024, including:

- Successfully completed commissioning a new water treatment plant that will supply demineralized water to the Darlington GS units as part of the operations cycle, ensuring reliable operations over the station's service life; and
- Successfully completed the replacement of key fuel handling equipment, including key lifting components for the fuel handling system and two of the eight fuelling machine heads. These projects will ensure reliable operations of the Darlington GS fuel handling equipment over the station's service life.

Based on the results of planned inspections of the units of the Darlington GS, OPG has identified that the primary moisture separators, a component of steam generators (SG), require replacement on all units to ensure ongoing safe, reliable and efficient operations throughout the station's extended lifespan. The function of the primary moisture separators is to provide high quality dry steam to the downstream turbine equipment. There are four SGs in each Darlington GS unit and each SG has 104 primary moisture separators. The replacement of the primary moisture separators in the first two SGs in Unit 3 was completed in 2023. The replacement of the four SGs in Unit 1 and the four SGs in Unit 4 was completed in the second quarter of 2024 and the fourth quarter of 2024, respectively. Actual life-to-date capital expenditures are $270 million as of December 31, 2024 and tracking below the approved budget of $380 million. The post-replacement inspection work on Unit 4 is expected to be completed in the first half of 2025, marking the completion of the project. The scope of work for Unit 2 and the remaining two SGs in Unit 3 is planned to be executed under a future project.

OPG's power reactor operating licence for the Darlington GS is valid until November 30, 2025. In June 2024, the CNSC announced its decision to amend the operating licence to authorize the production of the cobalt-60 radioisotope. In May 2024, OPG submitted an application to renew the operating licence for the Darlington GS for a period of 30 years beyond November 2025. The two-part public hearing on the application is scheduled to be held by the CNSC in March 2025 and June 2025. The first harvest of the cobalt-60 radioisotope at the Darlington GS is expected by 2028. Cobalt-60 radioisotopes are produced mainly for use in the health industry to sterilize surgical and medical supplies.

Renewable Generation Operations

As at December 31, 2024, OPG's renewable generation fleet comprises 54 regulated and 12 non-regulated hydroelectric generating station and one solar facility located in Ontario, and through Eagle Creek, 85 wholly or jointly owned and operated hydroelectric generating stations located throughout the United States.

The objectives of OPG's hydroelectric operations include operating and maintaining the generating facilities in a safe, reliable, efficient and cost-effective manner, while pursuing opportunities to increase the output and generating capacity of the fleet. OPG aims to increase the hydroelectric facilities' output by improving operational flexibility, enhancing reliability, optimizing outage planning and, subject to water conditions, increasing availability to meet electricity system demand. OPG continues to evaluate and implement plans to increase generating capacity, improve operational performance and extend the operating life of its hydroelectric generating assets.

Given the very long-term nature of the Company's hydroelectric fleet, OPG's plans to maximize the fleet's value are often accomplished through multi-year capital investment and other programs, including replacements and upgrades of turbine runners, and periodic refurbishment or replacement of existing generators, transformers and control systems. Where economical and practical, OPG also pursues opportunities to expand or redevelop its existing hydroelectric stations. To support effective operations and ensure continued high levels of safety, OPG has comprehensive programs in place to identify, prioritize and execute any necessary repair, rehabilitation or replacement work for civil hydroelectric structures. OPG seeks to enhance equipment reliability monitoring, reporting and management to support asset maintenance programs based on the condition of the facilities.

The Company continues to progress on an ongoing refurbishment program for its hydroelectric generating units across Ontario. During 2024, activities related to this program included the following:

- Initiated the execution of the refurbishment of Unit G4 at the Sir Adam Beck I GS, the first of the 19 units planned to undergo refurbishment at the Sir Adam Beck I and II generating stations. As of December 31, 2024, year-to-date and life-to-date capital expenditures for the refurbishment of both Sir Adam Beck I and II generating stations were $18 million and $23 million, respectively;
- Initiated the execution of the refurbishment of Unit 12 at the R.H. Saunders GS and continued the execution of the refurbishment of Unit 9, the first two of the station's 16 units planned to undergo refurbishment. As of December 31, 2024, year-to-date and life-to-date capital expenditures for the refurbishment of the R.H. Saunders GS were $19 million and $52 million, respectively;

- Completed the refurbishment of Unit 1 at the Barrett Chute GS and continued the execution of the refurbishment on the station's Unit 2. As of December 31, 2024, year-to-date and life-to-date capital expenditures for the station's refurbishment were $8 million and $19 million, respectively; and
- Initiated the execution of the refurbishment of Unit 1 at the Otter Rapids GS and continued the execution of the refurbishment on the station's Unit 2. As of December 31, 2024, year-to-date and life-to-date capital expenditures for the station's refurbishment were $20 million and $47 million, respectively.

Additionally, during 2024, the Company completed the replacement of the existing headgates at the Sir Adam Beck II GS, and the construction of the Otter Rapids Project Camp that will facilitate efficiencies in the execution of refurbishment work at remote generating stations in northern Ontario. Construction activities continue to progress on the rehabilitation of the concrete infrastructure at the R.H. Saunders GS, the Frederick House Lake Dam and other generating stations across Ontario.

On December 3, 2024, the Office of the Auditor General of Ontario released a Follow-Up Report building on its 2022 Performance Audit on the management and maintenance of the Company's hydroelectric fleet. In the Follow-Up Report, OPG was identified as one of the three auditees, out of the total of 16 auditees, that made the most progress toward fully implementing the recommended actions.

OPG coordinates and collaborates with various government agencies, municipalities, Indigenous partners and community stakeholders to ensure the river systems on which the Company operates are managed safely and effectively, while meeting electricity generation needs. Eastern and Southern Ontario experienced a number of heavy rainfall events in the spring and summer of 2024, resulting in sharp increases in water levels and flows in some areas. These wet seasons followed a relatively dry winter and were succeeded by a relatively dry fall across the province. OPG managed these conditions safely and effectively by maintaining a strong focus on dam and public safety and coordinating with municipalities and community stakeholders in the affected watersheds during both high and low water flow conditions.

Thermal Operations

OPG's thermal generation fleet comprises one oil/gas dual-fueled generating station, one biomass-fueled generating station, and four combined cycle plants operated through Atura Power.

These stations, which typically operate as peaking or cycling dispatchable facilities under their respective ESAs with the IESO, are an important component of maintaining the current and future reliability of Ontario's electricity system. They provide the system with the flexibility to meet changing daily system demand and capacity requirements, and enable variable sources of renewable generation such as wind and solar.

As of December 31, 2024, the contracts for Atura Power's facilities have the following terms and generating capacities, including generating capacity upgrades awarded by the IESO in 2023 and expected to be in service in 2025:

Generating Facility	Original Contract Expiry Date	Current Contract Expiry Date	Current in-Service Capacity (MW) [1]	Average Upgrade Capacity (MW)
Brighton Beach GS [2]	July 2024	July 2034	570	42.5
Portlands Energy Centre [3]	April 2029	April 2029	562	50.0
Halton Hills GS [4]	August 2030	April 2035	683	31.5
Napanee GS	March 2040	March 2040	900	-

[1] The current in-service generating capacity excludes average upgrade capacity.
[2] The facility operated under an energy conversion agreement with Shell Energy North America (Canada) Inc. until July 15, 2024. Effective July 16, 2024, the facility operates under a new ESA with the IESO for a term of 10 years.
[3] The ESA includes an option for Atura Power or the IESO to exercise, in 2028, an extension of the contract expiry by five years under certain conditions, inclusive of the generating capacity upgrades awarded in 2023.
[4] Pursuant to generating capacity upgrades awarded by the IESO in 2023, the contractual average capacity upgrade at the Halton Hills GS of 31.5 MW was placed in service and became effective February 3, 2025.

In September 2024, OPG and the IESO entered into an amended and restated ESA for the Atikokan GS, extending the contract expiry to July 2029. The extension allows the facility to continue providing renewable power for Ontario's electricity grid using biomass fuel. Atikokan GS is the largest 100 percent biomass-fueled plant in North America, providing renewable energy that can be dispatched when Ontario's power system requires it.

OPG's strategy in operating thermal generating stations is to ensure availability to meet electricity system requirements over the assets' expected remaining service lives, through station reinvestment within technical, regulatory and contractual constraints, and with an expectation of achieving an appropriate return on investment. In support of these objectives, thermal outage planning leverages agile asset management programs to prioritize equipment risks and optimize work program timing.

Improving Operational Efficiency

As part of a commitment to operational excellence, OPG is focused on pursuing productivity improvements and efficiencies in operating costs across the organization, while ensuring no adverse impact on the safety, reliability and environmental sustainability of the Company's operations. The Company continues to build on efficiencies achieved to date, leveraging investments in technology and innovation, improvements in business processes and internal service delivery models, strategic sourcing initiatives, workspace optimization, and resourcing strategies. Strategies to improve cost performance and organizational capability are implemented at the enterprise and business unit level.

The identification and continued pursuit of operational efficiencies is driven by enterprise-wide targets, set with a view to ensure the cost effectiveness of ongoing operations while supporting the advancement of corporate growth and transformation strategies and managing risks. Accomplishing these objectives is anchored in leveraging a highly skilled, high-performing, diverse and engaged workforce. OPG will continue to review its operating cost model and supporting business strategies as it enters a period with multiple planned major projects in support of energy transition and future electricity needs, including the DNNP and the planned refurbishment of Units 5 to 8 of the Pickering GS.

OPG is continuing to advance an enterprise-wide strategy to align the Company's digital infrastructure with its strategic objectives and to drive increased value from investments in technology. The strategy is focused on implementing scalable information technology infrastructure, enhancing mobility, connectivity and collaboration, streamlining information technology service support, embedding increased automation and artificial intelligence technologies, protecting digital assets, and improving data management and analytics capability. The goals of the strategy are to increase field and office productivity, improve equipment reliability and station performance, increase organizational agility, strengthen cybersecurity, and reduce operating costs.

Sale of Assets

In July 2023, Eagle Creek entered into agreements to sell 22 hydroelectric generating stations in the US with a total generating capacity of approximately 47 MW, along with two storage reservoirs in the Mid-Western US. In June 2024, the transaction was terminated. Following the termination, the criteria for classifying these assets as held for sale were no longer met, and the assets were reclassified to property, plant and equipment (PP&E) and intangible assets on the consolidated balance sheet.



Project Excellence

OPG is undertaking a number of generation development and other projects to maximize the value of and expand its generating fleet in support of Ontario's electricity system and beyond, striving for excellence in the planning and delivery of all capital and maintenance projects across the organization.

OPG's vision for project excellence is to be an industry leader in project management capability and performance. As part of its commitment to project excellence, OPG continues to enhance and streamline its approach to project planning and execution, with the goal of delivering all projects safely, on time, on budget and with high quality. Achieving project excellence involves, among others: leveraging a common, scalable project delivery model based on industry best practices across the enterprise, establishing strong project management teams to effectively execute projects, monitoring and controlling performance, optimizing contracting strategies, and engaging qualified and experienced engineering, procurement and construction vendors. The achievement of these objectives at OPG is facilitated by a centralized enterprise projects organization that ensures the necessary processes, tools and expertise are in place for project excellence.

Darlington Refurbishment

The Darlington Refurbishment project commenced in 2016 as the four Darlington GS units were approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by at least 30 years. The refurbishment of the first unit, Unit 2, was completed in June 2020. The refurbishment of the second unit, Unit 3, was completed in July 2023, ahead of schedule. The refurbishment of the third unit, Unit 1, was completed in November 2024, ahead of its original schedule set for the second quarter of 2025. The refurbishment of the last unit, Unit 4, commenced after Unit 3 was returned to service and is scheduled to be completed in 2026.

The Darlington Refurbishment project is a multi-phase program comprising the following five major sub-projects:

- Defueling and Fuel Handling, which involves the defueling of the reactors and the refurbishment of the fuel handling equipment;
- Re-tube and Feeder Replacement (RFR), which includes the removal and replacement of feeder tubes and fuel channel assemblies in each reactor;
- Turbines and Generators, which consists of inspections and repairs of turbine generator sets and the replacement of analog control systems with digital control systems for Units 3, 4 and 1;
- Steam Generators, which includes mechanical cleaning, water lancing and inspection and maintenance work on the generators; and
- Balance of Plant, which consists of work on a number of projects to replace or repair certain other station components.

The RFR sub-project is the largest sub-project and represents a majority of the critical path schedule.

The major sub-projects are executed over four major segments for each unit:

- Shut Down, which involves removing fuel from the reactor and islanding the unit;
- Disassembly, which involves removing the required reactor components including feeder tubes, fuel channels and calandria tubes;
- Reassembly, which involves procuring, installing and inspecting new reactor components; and
- Power Up, which involves loading new fuel into the reactor, restoring the reactor vault, reconnecting the unit to the rest of the station, and returning the unit to service.

Unit 1 was returned to service in November 2024 in line with the Company's high quality and safety standards, following successful completion of start-up activities and receipt of all appropriate regulatory approvals from the CNSC. Upon the unit returning to service, capital expenditures totalling approximately $1.7 billion were placed in service.

Unit 4 refurbishment activities are progressing on schedule, having completed the Disassembly segment with the completion of the removal of fuel channel assemblies in September 2024 and are currently in the Reassembly segment. The installation of calandria tubes was completed in January 2025. The fuel channel installation series is in progress and planned to be completed in the second half of 2025. The upper and middle feeder installation series are also continuing, with the installation of 960 new feeder tubes being completed in two segments, starting with the upper and middle feeders and followed by the lower feeders. As part of the refurbishment, OPG also continues to progress through the reconditioning of the Unit 4 turbine generator, with the overhaul of the turbine generator and the installation of the turbine control systems upgrade expected to be completed in the second half of 2025.

The total project costs, including the impacts of the COVID-19 pandemic, are on track to meet the $12.8 billion budget.

Smoky Falls Dam Safety Project

OPG has substantially completed the Smoky Falls Dam Safety project to improve dam safety at the Smoky Falls hydroelectric GS, located along the Lower Mattagami River in northeastern Ontario. The project rehabilitated the 100-year-old spillway and sluiceway structures in compliance with dam safety requirements established by the Province.

During 2024, the two new sluicegates were commissioned and placed in service ahead of the original schedule. The concrete closure of the west sluiceway was also successfully completed along with the removal of the west sluiceway superstructure and gates. With major construction activities completed during the year, the project has transitioned to site rehabilitation and closure activities, which will continue into 2025. The project is tracking within the approved budget of $390 million.

The Smoky Falls Dam supports OPG's hydroelectric generating stations on the Lower Mattagami River. The project costs are expected to be recovered under the ESA in place for the Lower Mattagami generating stations.

Atura Power Development Projects

Atura Power is advancing a project to construct the NHC in Niagara Falls, Ontario as its first site for large-scale hydrogen production. The facility will use a 20 MW electrolyzer to produce low-carbon hydrogen by utilizing water and hydroelectricity as inputs. Engineering and design activities were completed during 2024, and the project has advanced further groundwork with most substation foundations and cable trenches installed. The NHC is expected to be completed in 2026.

Atura Power is executing a project to build a 250 MW four-hour battery energy storage system at the Napanee GS site. The Napanee BESS will support Ontario's energy grid by drawing and storing electricity off-peak when power demand is low and returning it to the system at times of higher electricity demand. Following the completion of design work and procurement of critical equipment, on-site construction activities commenced during 2024, with critical equipment foundation work underway. The project is expected to be completed in 2026 and will operate under a 21-year capacity agreement with the IESO.

Details on the project to expand the combined cycle plant at the Napanee GS can be found in the section, *Significant Developments* under the heading, *Napanee Combined Cycle Generating Station Expansion*.

OPG's major projects in the execution phase as at December 31, 2024 are outlined below.

Project *(millions of dollars)*	Capital Expenditures Year-to-date	 Life-to-date	Approved Budget	Expected In-service Date	Current Status
Darlington Refurbishment Project	987	11,190	12,800 [1]	Unit 4 – 2026	Unit 1 was successfully returned to service in November 2024. Unit 4 refurbishment is progressing on schedule and is currently in the Reassembly segment. The project is tracking on budget.
Redevelopment of Kakabeka Falls Hydroelectric GS	34	39	519	2028	The project entered the execution phase in November 2024 and is progressing. For further details, refer to the section, *Significant Developments – Project Excellence* under the heading, *Redevelopment of Hydroelectric Generating Stations*.
Atura Power Development Projects	206	288	1,500 [2]	Niagara Hydrogen Centre – 2026 Napanee BESS – 2026 Napanee Combined Cycle GS Expansion Project – 2028	Engineering and design activities for the NHC project were completed during the year. The project continues to advance additional groundwork. Following the completion of design work and procurement of critical equipment, the Napanee BESS project continues to advance on-site construction, on schedule. Engineering, design and permitting activities for the Napanee GS Expansion project are progressing on schedule, with procurement of critical equipment completed. These projects are tracking within the total approved budget.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units of the Darlington GS.
[2] The total project budget of approximately $1.5 billion is for the Niagara Hydrogen Centre, the Napanee BESS and the Napanee Combined Cycle GS Expansion projects.



Financial Strength

As a commercial enterprise, OPG's financial priority is to ensure a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and supports expansion of the business.

Inherent in this priority are four objectives:

- Increasing revenue, reducing costs and achieving appropriate return;
- Ensuring availability of cost effective funding for operational needs, generation development projects and other business opportunities, and long-term obligations;
- Pursuing opportunities to expand the existing core business and capitalize on new growth paths including emerging clean energy opportunities; and
- Managing risks, which is discussed in the section, *Risk Management*.

Increasing Revenue, Reducing Costs and Achieving Appropriate Return

In line with its commercial mandate, OPG is focused on increasing revenue and net income, and achieving an appropriate return on the Shareholder's investment, while seeking to minimize the impact on electricity customers through continuous improvement in the Company's cost structure.

For regulated operations, achievement of the above objectives is largely dependent on outcomes of OPG's applications for regulated prices to the OEB and prudent growth of rate base earning a return. OPG is focused on demonstrating in its applications for regulated prices that the costs required to operate and invest in the Company's regulated assets are reasonable, being prudently incurred and should be fully recovered, and that the Shareholder's investment in these assets should earn an appropriate return.

For the Regulated – Nuclear Generation business segment, the following rate base levels, OPG-specific deemed equity percentage, and formulaic rates of ROE established by the OEB on a generic basis are reflected in OPG's approved base regulated prices:

	ROE	**Equity** [1]	**Rate Base**			
(millions of dollars - except where noted)	**2022 - 2026**		**2023**	**2024**	**2025**	**2026**
Regulated – Nuclear Generation [2]	**8.66%**	**45%**	8,615	**11,033**	12,189	12,992

[1] The remaining 55 percent of rate base is deemed to be financed by debt, with an average approved cost rate of 3.6 percent per annum reflected in the nuclear base regulated prices for the 2022-2026 period.

[2] Excludes differences between approved forecast rate base additions and actual rate base additions for qualifying investments, where the revenue requirement impact of such differences is trued up through regulatory accounts, subject to the OEB's review and approval. These differences are included in rate base values shown in the table once reflected in OEB-approved base regulated prices.

For the regulated hydroelectric facilities, there is a separately approved rate base, deemed equity percentage and ROE rate. The most recent OEB-approved hydroelectric rate base value was $7,490 million, with an ROE of 9.33 percent and a deemed equity of 45 percent, all of which were reflected in the hydroelectric base regulated prices in effect prior to June 1, 2017. The hydroelectric base regulated prices for the period from June 1, 2017 to December 31, 2021 were determined by annually escalating the base regulated prices in effect prior to June 1, 2017, with some adjustments, using an approved formula. Pursuant to *Ontario Regulation 53/05*, the hydroelectric base regulated price for the period from January 1, 2022 to December 31, 2026 is equal to the 2021 hydroelectric base regulated price.

OPG continues to invest in the nuclear and hydroelectric rate base, including through the Darlington Refurbishment project. In establishing the 2022-2026 nuclear base regulated prices, the OEB approved an additional $6.8 billion in Darlington Refurbishment in-service capital additions to rate base, including the forecasted return to service from the refurbishment of Units 3, 1 and 4 of the Darlington GS at the time, bringing the total approved nuclear rate base to $13.0 billion by 2026.

As discussed in the section, *Core Business and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability*, OPG continues to undertake an extensive capital program across its regulated hydroelectric operations, including the refurbishment and redevelopment of the generating facilities to ensure their continued safe and reliable operations. These renewable assets can have very long service lives and, with either maintenance efforts or rebuilding, can continue to supply electricity and be reflected in rate base for the foreseeable future.

The revenue requirement impact of differences in the amount or timing between OEB approved forecast rate base additions and actual capital in-service additions related to OPG's investments to increase the output of, refurbish or add generating capacity to one or more of its nuclear or hydroelectric regulated facilities, including the Darlington Refurbishment project, are recorded for future review and disposition in a variance account authorized by the OEB pursuant to *Ontario Regulation 53/05*. The regulation also provides for a variance account to record and recover the revenue requirement impact of differences between any OEB approved forecast capital and non-capital costs incurred for new nuclear generation facilities and such actual costs, subject to review by the OEB.

As part of OPG's 2022-2026 application for new regulated prices, the OEB approved a mechanism for customers to share, on a 50 percent basis, in the regulatory earnings achieved by OPG's regulated operations that are more than 100 basis points over the approved ROE levels, assessed on a five-year cumulative basis over the 2022-2026 period. Any such amounts shared with customers will be recorded in a separate deferral account for disposition following the five-year period. Additionally, the regulatory frameworks in effect for the 2022-2026 period include a symmetrical 300 basis points trigger around the approved ROE, based on achieved regulatory earnings, where the OEB may initiate a regulatory review.

In 2024, the OEB initiated a generic cost of capital proceeding to review the methodology for determining the cost of capital parameters and deemed capital structure used for setting utility rates, which was last reviewed by the OEB in 2009. OPG is participating in this proceeding. The outcome of the proceeding is expected in 2025.

For generation assets that do not form part of the rate regulated operations, OPG generally seeks to secure long-term revenue arrangements that support an appropriate return on the investment. In line with this strategy, all of OPG's non-regulated facilities in Ontario are subject to ESAs with the IESO. These contracts are generally designed to provide for recovery of operating costs and capital investment in the underlying facilities and a return on invested capital, subject to the facilities continuing to meet their contractual obligations.

While a number of the Company's generating facilities in the US are subject to energy and capacity supply contracts, and longer term contracts are pursued where considered financially advantageous, the majority of OPG's generating facilities in the US currently earn revenue from wholesale electricity markets. Although revenue from wholesale electricity markets in the US represents a small portion of OPG's overall revenue, the Company may enter into hedging arrangements from time to time to further mitigate the commodity price risks.

Ensuring Availability of Cost Effective Funding

OPG actively monitors its funding requirements and forecasts availability of funds to ensure that it can meet the Company's operational needs, project and other commitments, and long-term obligations. In addition to funds generated from operations, OPG utilizes the following primary funding sources: commercial paper; letters of credit; credit facilities; public debt offerings; debt sourced from the Ontario Electricity Financial Corporation (OEFC) and Ontario Financing Authority (OFA), agencies of the Province; and private placement and other project financing arrangements.

Credit Ratings

Maintaining an investment grade credit rating supports OPG's ability to access cost effective financing. As at December 31, 2024, the Company's credit ratings were as follows:

Type of Rating	DBRS Limited (DBRS) [1]	S&P Global Ratings (S&P) [2]	Moody's Investors Service (Moody's) [3]
Issuer rating	A (low)	BBB+	A3
Senior unsecured debt	A (low)	BBB+	A3
Trend/Outlook	Stable	Stable	Stable
Commercial paper program – Canada	R-1 (low)	A-1 (low)	NR [4]
Commercial paper program – US	NR [4]	A-2	P-2

[1] In April 2024, DBRS confirmed OPG's A (low) issuer rating, A (low) senior unsecured debt rating and R-1 (low) Canadian commercial paper rating, all with Stable trends.
[2] In August 2024, S&P confirmed OPG's ratings including BBB+ issuer rating with stable outlook, BBB+ senior unsecured debt rating and A-1 (low) Canada commercial paper rating.
[3] In May 2024, Moody's confirmed OPG's A3 issuer rating with stable outlook, A3 senior unsecured debt rating and P-2 US commercial paper rating.
[4] NR indicates no rating assigned.

Additional discussion of the Company's credit facilities and liquidity can be found in the section, *Liquidity and Capital Resources*.

Federal Clean Energy Investment Tax Credits

In March 2023, the Government of Canada announced certain refundable investment tax credits (ITC) for clean energy investments. The Clean Technology ITC (CTITC) and the Clean Hydrogen ITC (CHITC) were enacted during the second quarter of 2024. The CTITC provides a 30 percent refundable tax credit and the CHITC provides a refundable tax credit ranging from 15 percent to 40 percent depending on the carbon intensity of the project, and both credits are available to federally taxable entities. If certain labour conditions are not met, these refundable credits are reduced by ten percent. OPG's federally taxable entities making eligible investments may qualify for the CTITC and the CHITC.

Draft legislation for the Clean Electricity ITC (CEITC), a 15 percent refundable tax credit available to federally tax exempt entities including OPG, was published by the Government of Canada in August 2024. The draft legislation was terminated upon prorogation of Parliament in January 2025. Certain OPG projects are expected to qualify for the CEITC if it is legislated. The Company continues to monitor CEITC developments.

Ontario Court Bill 124 Decision

Protecting a Sustainable Public Sector for Future Generations Act, 2019 (Bill 124), which came into force on November 8, 2019, set limits on compensation increases for unionized and non-unionized employees in the Ontario public sector and applied to OPG. Bill 124 limited the maximum annual increase in both wages and total compensation to one percent for a three-year period, subject to certain exceptions. A broad range of unions and organizations challenged the constitutionality of Bill 124. In a decision dated November 29, 2022, the Ontario Superior Court found that Bill 124 was unconstitutional and declared it to be void and of no effect. On December 29, 2022, the Government of Ontario filed an appeal of the decision with the Ontario Court of Appeal. On February 12, 2024, the Ontario Court of Appeal upheld the lower court decision and found Bill 124 to be unconstitutional as it pertains to unionized employees but constitutional in its application to non-unionized employees. Following the decision, the Province repealed Bill 124 in its entirety.

OPG's approved regulated prices for the 2022-2026 period were set on the basis of cost forecasts that assumed the application of Bill 124. In March 2023, OPG filed an application with the OEB requesting to establish a variance account to record and therefore offset compensation cost impacts attributable to the nuclear facilities as a result of the Bill 124 Court Decision, subject to future review and disposition by the OEB. In June 2023, the OEB issued a decision and order denying OPG's request. In July 2023, OPG filed a motion asking the OEB to review the June 2023 decision, which was reaffirmed by the OEB in its decision on OPG's motion issued in October 2023. As a result, OPG is unable to record compensation cost impacts of the Bill 124 Court Decision in the proposed variance account.

Growth and Transformation

OPG strives to be a leader in the North American energy transition, while maintaining and expanding the Company's scale and industry leadership through the pursuit of commercial-based opportunities. This strategy considers the Company's financial position, anticipated future changes in the generating fleet, and the evolving external environment in which it operates. The strategy is also informed by industry, technological, environmental, social, and economic factors. Opportunities are evaluated on an ongoing basis using financial and risk-based analyses as well as the application of strategic considerations, including the evaluation of partnership opportunities with other entities where aligned with OPG's business objectives.

OPG's strategy includes the renewal and expansion of the Company's portfolio of generating assets, including the redevelopment and expansion of existing sites, pursuit of new developments and business acquisitions. The strategy leverages OPG's operating and project development expertise across its diverse physical asset base. Acquisition opportunities consider potential operating synergies, strategic benefits, financial returns and risk profile.

OPG also actively seeks to expand beyond its core generation business, either directly or through its subsidiaries and partnerships, with investments in innovative technologies and new lines of business in the electricity sector, including nuclear innovation, transport electrification, low-carbon hydrogen production, battery energy storage, hydroelectric pumped storage, and other opportunities.

New Nuclear

In January 2024, OPG and Capital Power Corporation, an Alberta-based company, entered into an agreement to jointly assess the feasibility of developing and deploying grid-scale SMRs in Alberta, including possible ownership and operating structures, over the next two years.

OPG is preparing for possible development of new large nuclear reactors in Ontario. This includes preparing information for the Wesleyville site to explore new nuclear opportunities with local communities and First Nations, as announced by the Province in January 2025, as well as continuing to evaluate the suitability of the Company's other existing sites for potential nuclear energy generation. OPG has also begun preliminary evaluations of available large nuclear reactor technologies and, subject to successful engagement with local communities and First Nations, approaches to a potential site licensing process. The costs for these activities are recorded in an existing regulatory account for future recovery, subject to review by the OEB.

Nuclear Project Management Organization Services

In June 2024, Canadian Nuclear Partners S.A. (CNPSA), a subsidiary of Laurentis Energy Partners (LEP), a wholly-owned subsidiary of OPG, entered into a long-term framework agreement with S.N. Nuclearelectrica S.A., a Romania-based nuclear energy company. Pursuant to the agreement, CNPSA will provide project management organization services necessary for the preparation and implementation of the Unit 1 refurbishment project at the Cernavoda Nuclear Power Plant in Romania, including project management, technical assistance and staff training.

Global First Power Partnership Divestiture

In August 2024, OPG executed a separation agreement under which OPG divested its interest in Global First Power Limited and Global First Power Limited Partnership to USNC-Power, Ltd.

Marmora Pumped Hydroelectric Storage Facility Project Exit

During 2024, OPG exited the partnership with Northland Power Inc. for a proposed 400 MW hydroelectric pumped storage project in Marmora, Ontario, with Northland Power Inc. becoming the sole project developer.

Ivy Charging Network Divestiture

Ivy Charging Network (Ivy), a joint-venture between OPG and a subsidiary of Hydro One Limited (Hydro One), continued to own and operate electrical vehicle (EV) fast charging stations throughout Ontario during 2024, with a total of 81 charging ports and 154 fast chargers in operation as of the end of the year.

In the first quarter of 2025, OPG entered into an agreement to divest its interest in the Ivy partnership to Hydro One. The transaction was completed during the same quarter.

Clean Energy Credits

Building on the Company's strategy to help the markets where it operates achieve net-zero carbon economies, OPG offers electricity consumers voluntary Clean Energy Credits (CECs) from its hydroelectric and nuclear facilities in Ontario and, through Eagle Creek, offers Renewable Energy Credits (RECs) from its hydroelectric facilities in the United States. The purchase of CECs and RECs allows electricity consumers to demonstrate that their electricity comes from clean generating sources.

In January 2025, OPG entered into an agreement with a leading global automotive supplier, Magna International Inc. (Magna), to supply CECs sourced from the Sir Adam Beck hydroelectric generating complex. The majority of the proceeds from the sale of CECs will be directed to the Province's Future Clean Electricity Fund, which will help lower costs for electricity customers by supporting the development of new clean energy projects in Ontario.



Social Licence

OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public health and safety and corporate citizenship, including environmental stewardship, transparency, community engagement and Indigenous relations. The Company also strives to be a leader in climate change action, ED&I practices, and in advancing reconciliation with Indigenous peoples.

Further details on social licence activities and initiatives can be found in the section, *Environmental, Social, Governance and Sustainability*.

Outlook

Operating Performance

OPG expects net income for the 2025 year to be higher than the 2024 year, primarily due to higher nuclear electricity generation anticipated in 2025 as a result of three units of the Darlington GS being operational for the full year and fewer planned outage days in the cyclical maintenance schedule for the Darlington GS, partially offset by the end of commercial operation of Unit 1 and Unit 4 of the Pickering GS in 2024.

The OEB-approved regulated prices are expected to continue to provide regulatory certainty up to 2026. Additionally, regulatory accounts are expected to continue to reduce the relative variability of the regulated business segments' contribution to the Company's net income, particularly for the Regulated – Hydroelectric Generation business segment. This includes accounts that capture the gross margin impact of variability in water flows and forgone production due to

SBG conditions at the regulated hydroelectric stations. There are no regulatory accounts in place related to the impact of variability in OPG's nuclear stations' generation performance on revenue from base regulated prices.

The ESAs in place for the Ontario-based non-regulated assets reported in the Contracted Hydroelectric and Other Generation and Atura Power business segments are expected to contribute a generally stable level of earnings in 2025, consistent with 2024. Earnings from the US-based hydroelectric facilities reported in the Contracted Hydroelectric and Other Generation segment are subject to variability in water flows and the impact of wholesale electricity prices on uncontracted facilities.

The Company's operating results in 2025 may be impacted by macro-economic factors and geopolitical events, including tariffs and other trade restrictions, as discussed further in the section, *Risk Management.*

Nuclear Segregated Funds

OPG's operating results can be affected by earnings on the Nuclear Segregated Funds as part of the Regulated – Nuclear Sustainability Services business segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the Ontario Nuclear Funds Agreement (ONFA) between OPG and the Province, rates of return earned in a given period are subject to volatility due to financial market conditions and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province, changes in the Ontario consumer price index (CPI). This volatility can cause fluctuations in the Company's net income in the short term if the funds are not in a fully funded or overfunded position. The volatility is reduced by the impact of an OEB-authorized regulatory account.

As at December 31, 2024, the Decommissioning Segregated Fund was overfunded by approximately 47 percent and, after taking into account the rate of return guarantee provided by the Province, the Used Fuel Segregated Fund was overfunded by approximately ten percent based on the current approved ONFA reference plan in effect for the years 2022 to 2026 (2022 ONFA Reference Plan).

Capital Expenditures

OPG's total capital expenditures for 2025 are planned to be approximately $5 billion. The annual forecast is higher than the capital expenditures in 2024, primarily reflecting the advancement of major projects, including: definition phase activities for the planned refurbishment of Units 5 to 8 at the Pickering GS, planned start of construction activities for the first SMR at the DNNP site, subject to CNSC regulatory approval and other requisite approvals, execution of redevelopment and refurbishments projects across the hydroelectric fleet, and advancement of Atura Power's development projects.

The capital expenditure outlook may be impacted by finalization of project budgets and timing of project approvals, as well as macro-economic factors and geopolitical events, including potential tariffs and other trade restriction impacts, as discussed further in the section, *Risk Management.*

Financing and Liquidity

The Company expects to generate a higher level of cash flow from operating activities in 2025 compared to 2024, mainly due to higher nuclear electricity generation anticipated in 2025. The level of cash flow from operating activities in 2025 will also be affected by electricity generation volumes at the hydroelectric generating stations depending on water conditions. Taking into account the planned capital expenditure program, OPG expects existing funding sources to continue to be sufficient to meet financing requirements and support ongoing liquidity during 2025. Further details of OPG's credit facilities can be found in the section, *Liquidity and Capital Resources* under the heading, *Financing Activities*.

ENVIRONMENTAL, SOCIAL, GOVERNANCE AND SUSTAINABILITY

OPG recognizes that operating in a manner consistent with ESG principles is directly connected to business success and is expected by the Company's customers, stakeholders, Rightsholders and Shareholder. As Ontario's largest clean, low-carbon energy provider, the Company strives to be a leader in sustainability, climate change action, and Indigenous relations. This is accomplished through the implementation of operational and growth strategies that minimize the Company's environmental impacts, support reductions in greenhouse gas (GHG) emissions, increase operations' resilience to climate change impacts, and advance Indigenous reconciliation, all while taking into account impacts on customers. A central part of OPG's ESG and sustainability focus is its commitment to becoming a global ED&I best practice leader by 2030.

OPG's latest Integrated ESG and Annual Report is available on the Company's website at www.opg.com.

Health and Safety

Workplace health and safety and public safety are fundamental core values at OPG. OPG is committed to operating its facilities in a safe, secure and reliable manner. Health and safety are overriding priorities in all activities performed at OPG's generating and other facilities, and employees and contractors are expected to conduct themselves in a manner that ensures workplace health and safety and public safety in line with the Company's health and safety culture, the Employee Health and Safety Policy and the Safe Operations Policy.

OPG is committed to achieving excellent performance in the area of workplace health and safety through continuous improvement and a strong health and safety culture. OPG utilizes integrated health and safety management systems and a set of operational risk control procedures to ensure continued monitoring of health and safety performance and to support continuous learning and improvement in this area. Over the past several years, OPG has stood in the top quartile of its comparator Canadian electrical utilities in various safety performance metrics. In November 2024, OPG received the Electricity Canada President's Award of Excellence for Employee Safety, in recognition of OPG's top safety performance within the comparator group in the previous year.

OPG uses Total Recordable Injury Frequency (TRIF) as a performance measure to benchmark OPG's performance against other Electricity Canada utilities. OPG also uses Serious Injury Incidence Rate (SIIR) as a key corporate safety metric. SIIR captures a more serious sub-set of injuries than the TRIF metric and helps OPG maintain a focus on high consequence hazards as part of its health and safety culture.

OPG's employee workplace safety performance as measured by the TRIF and SIIR indicators was as follows:

Safety data[1]	2024	2023
TRIF *(injuries per 200,000 hours)*	**0.23**	0.18
SIIR *(serious injuries per 200,000 hours)*	**0.02**	0.00

[1] Performance is inclusive of OPG and its subsidiaries.

OPG's TRIF and SIIR slightly increased in 2024 compared to 2023. To strengthen its safety performance, the Company continues to implement a number of initiatives to target injury and high-energy incident trends based on the analysis of safety events and the use of human performance tools including increased field supervisory oversight and monitoring the presence of safety defences.

Approaches to safe work planning, learning from events, employee engagement, field observations and coaching, and education and communication are also being continuously strengthened to reinforce safety as a foundational element of the Company's values-based culture. Additionally, employee safety has been identified as a key element of OPG's sustainability-linked credit facilities demonstrating OPG's commitment to employee safety.

Contractors are required to conduct work safely at OPG sites. In support of this requirement, OPG utilizes an independent contractor pre-qualification process, provides on-site safety support for many of its major projects, and works with contract partners to improve their health and safety programs to meet OPG's requirements.

OPG continues to promote a health and wellness program aimed at embedding a health culture that supports employees and their families in achieving an optimal level of health and functioning, through health education, health promotion, disease and injury prevention, and crisis intervention. This includes providing resources to support mental health and access to a virtual healthcare platform for employees and their families.

OPG continues to maintain a strong focus on the nuclear safety program and to invest in nuclear safety systems. To ensure continued public safety, radiation exposure to members of the public resulting from the operation of OPG's nuclear generating stations is estimated on an annual basis for individuals living or working near the stations. The annual dose to the public resulting from operations of each nuclear facility is expressed in microsieverts (μSv), which is an international unit of radiation dose measurement.

The doses to the public resulting from OPG's nuclear operations were as follows:

Annual public dose	2023		2022	
	μSv	% of annual legal limit [1]	μSv	% of annual legal limit [1]
Darlington GS	**0.7**	**<0.1%**	0.6	<0.1%
Pickering GS	**1.5**	**0.2%**	1.9	0.2%

[1] The annual legal limit is 1,000 μSv for each nuclear generating station.

While the public doses from OPG's nuclear operations for the 2024 operating year will not be finalized until the second quarter of 2025, they are not expected to differ significantly from the 2023 levels.

OPG remains committed to high standards of public safety on waterways around hydroelectric generating stations and dams, and continues to make investments in waterway public safety and dam safety upgrades. OPG's dam safety program encompasses dam safety, emergency management and public safety around dams in compliance with the Safe Operations Policy. The Company's practices in these areas for Ontario-based operations are routinely reviewed by an independent panel comprised of internationally recognized experts, who have consistently concluded that many aspects of OPG's dam safety program are industry leading, and a strong culture of continuous improvement exists. At its US-based facilities, OPG continues to advance investments in waterway and dam safety upgrades to ensure compliance with FERC regulations and a continuous improvement path toward the Company's Ontario-based assets.

Environmental

OPG is committed to meeting and, where appropriate, exceeding the Company's environmental obligations and commitments. Specifically, OPG's Environmental Policy commits the Company to:

- Maintain an environmental management system (EMS), and registration for this system to the ISO 14001 Environmental Management System standard for OPG, excluding subsidiaries;
- Work to prevent or mitigate adverse impacts on the environment with a long-term objective of continual improvement;
- Execute its Climate Change Plan and strive to achieve the milestones and goals therein; and
- Manage sites in a manner that strives to maintain or, where it makes business sense, enhance significant natural areas and associated species of concern.

Within the EMS, OPG sets environmental objectives and maintains planning, operational control and monitoring programs to manage its negative and positive impacts on the environment. The most significant environmental aspects of OPG's operations include spills, water flow and level changes, radiological emissions, non-radiological emissions, L&ILW, non-radiological waste, wildlife habitat, and fish impingement, entrainment and spawning disruption.

The EMS is reviewed annually to ensure it remains appropriate to the purpose and context of the Company's operations. Environmental performance targets are set as part of the annual business planning process. These targets are based on past performance and external benchmarking to promote continual improvement. OPG met or outperformed its 2024 targets for spills, environmental infractions, carbon-14 emissions to air, volume of L&ILW produced, and tritium emissions to air and water. There were no significant environmental events during 2024.

OPG has developed biodiversity conservation plans that identify significant natural areas, conservation goals, threats and proposed actions to sustain biodiversity at the Company's operating sites and across Ontario. To maximize benefits and manage impacts, conservation initiatives include biodiversity monitoring, site naturalization, habitat creation and control of invasive species. During 2024, OPG continued to work with community and Indigenous partners to support regional ecosystems and biodiversity, including nature-based solutions to protect and restore habitat, and to promote biodiversity education and awareness to help restore Ontario's natural landscapes. In 2024, OPG and its conservation partners planted approximately 533,000 native trees and shrubs.

On December 17, 2024, the Government of Canada released final *Clean Electricity Regulations* (CER). Beginning in 2035, the CER will set limits on carbon dioxide emissions from fossil fuel-burning electricity generation units with a generating capacity of 25 MW or greater connected to an electricity system that is subject to North American Electric Reliability Corporation standards. OPG's Lennox GS, Atikokan GS and Atura Power's combined cycle plants must register under the CER by the end of 2025. OPG is assessing the impact of this regulation on its thermal generating facilities and will continue to monitor CER-related developments.

Details of OPG's environmental performance and initiatives to fulfill the Company's Environmental Policy can be found on the Company's website at www.opg.com.

Climate Change

OPG continues to monitor the development of voluntary sustainability and climate-related financial information disclosures that are measurable and relevant to investors and other stakeholders, including those of the International Sustainability Standards Board and the Canadian Sustainability Standards Board. OPG also continues to monitor the Canadian Securities Administrators' proposed mandatory climate-related disclosure requirements per National Instrument 51-107 – *Disclosure of Climate-related Matters*. OPG's current strategy, governance, risk management approach and initial performance metrics related to climate change are discussed below.

Climate Strategy

OPG recognizes the importance of developing and implementing climate change adaptation measures to ensure ongoing safe, reliable and cost-effective operation of its generating fleet over the medium and long term. Through its business strategies, the Company is also focused on maximizing the decarbonizing potential of its assets and the broader electricity sector as a means of mitigating climate change. This includes continue to embed climate change adaptation and mitigation as an enterprise-wide priority and a key principle in decision-making. In advancing these strategies, OPG seeks to make prudent investments in viable new technologies and to ensure that planned actions are executable and aligned with strategic, operational and financial objectives.

Climate Change Plan

OPG's Climate Change Plan released in 2020 describes the Company's ambition to be a North American clean energy leader and an enabler of efficient, economy-wide energy transition. The plan outlines OPG's goals and a range of solutions to help achieve decarbonization while balancing economic and environmental benefits and electricity system needs.

The Company has set the following goals as part of the Climate Change Plan:

- Become a net-zero carbon emissions company by 2040; and
- Support broader economy-wide decarbonization by 2050.

To pursue these goals, OPG has developed an action plan in the areas of carbon emissions reductions, climate change adaptation, energy sector innovation and climate change leadership.

Since the launch of its Climate Change Plan in 2020, OPG has made advancements in a number of areas with the objective of achieving sustainable, resilient operations and investing in the generation of low-carbon energy. This includes progressing the Darlington Refurbishment project, leading the deployments of SMRs, and safely maximizing

the operating life of Units 5 to 8 of the Pickering GS. OPG also continues to advance projects to increase the generating capacity of its hydroelectric generating stations, and is exploring the potential for new hydroelectric development. Through its subsidiaries, OPG is supporting the electrification of Ontario's transportation sector, laying the groundwork for low-carbon hydrogen production, and constructing a grid-connected battery energy storage system. OPG intends to periodically review and update the Climate Change Plan to reflect the Company's current climate-related initiatives and any changes to government policy, technology development and electricity supply and demand expectations.

OPG's Climate Change Plan can be found on the Company's website at www.opg.com.

Oversight of Climate-related Risks and Opportunities

OPG's Board is responsible for the governance and stewardship of the Company, including the oversight of climate-related risks and opportunities over the near and long term. On at least a quarterly basis, and during the annual strategy session, the Board engages with OPG's senior management on the Company's near-term and long-term business strategies, including climate-related matters. OPG's Climate Change Plan, which was reviewed and approved by the Board, is an integral part of the Company's overall business strategy and underpins OPG's corporate strategic planning process.

The Board's risk oversight responsibilities are fulfilled through OPG's Enterprise Risk Management (ERM) Framework, with oversight by the Audit and Risk Committee of the Board. The ERM Framework is used to manage the Company's risk profile, as well as its internal audit program. The ERM Framework assists the Board in understanding how risks may affect the Company and how they are being addressed by management. The Audit and Risk Committee receives quarterly reports from OPG's Chief Audit Executive on enterprise-wide risks and internal audit findings. Climate-related risks are being identified and managed as part of the ERM Framework. Further details on the Company's approach to risk management can be found in the section, *Risk Management*.

OPG's internal governance includes a documented framework to guide the management of climate change and a reporting structure for the Board's oversight of climate-related risks and opportunities. Board oversight of climate-related risks and opportunities is achieved through bi-annual reporting by OPG's Environment, Health and Safety department, with support from the Climate Steering Committee and other departments, as required.

OPG pension plan and Nuclear Segregated Funds investment strategies in equity markets, and of specific assets in the real estate and infrastructure portfolio, are guided by respective Responsible Investing Policies in place for the OPG pension plan and for the Nuclear Segregated Funds. OPG continues to build on the existing strategies to formalize a climate change action plan for the OPG pension plan and, in collaboration with the Province, for the Nuclear Segregated Funds that supports the Company's overall climate change goals.

Identification and Integration of Climate-related Risks

In recent years, OPG has experienced operational impacts exacerbated by changes in climate. The physical risks of severe weather events and changing climate parameters, such as precipitation patterns and intensity, and water and air temperatures, are expected to remain long-term concerns. In addition to the potential impacts on electricity generation at hydroelectric generating stations and cooling water efficiency at nuclear and thermal generating stations, changes in climate can also affect the reliability and life expectancy of major equipment. OPG's resilience against these risks is anticipated to increase as adaptation actions are identified and completed. Over the medium and long term, government policies and regulations in support of a shift to a lower-carbon economy may result in transition risks, such as changes in the electricity supply and demand profiles in the regions where OPG operates and impacts on the Company's carbon-based generating technologies.

OPG's strategy to guide the Company's adaptation priorities includes integrating considerations of climate-related risks and opportunities into applicable business processes, such as investment decisions and engineering processes, and implementing standardized decision supports to enable this integration. The Company is also continuing to evaluate and prioritize potential physical and transition risks over the near, medium and long term timeframes. As part of this process, OPG continues to increase data collection and develop modelling to better understand the range of potential climate impacts on the business and to identify opportunities for increasing resilience. OPG also participates in practical research studies with external consortiums and industry groups to develop and advance industry specific adaptation strategies and frameworks.

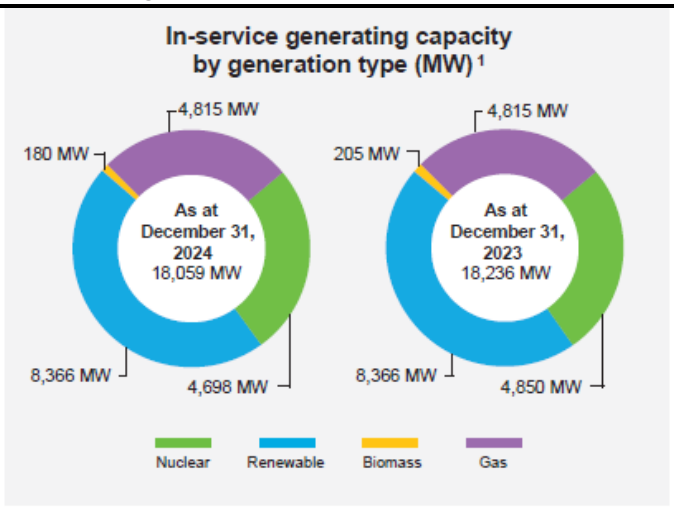
Internal Carbon Prices

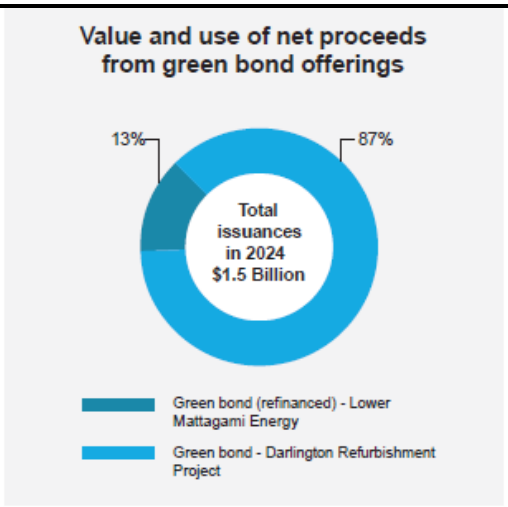
The Canadian federal *Greenhouse Gas Pollution Pricing Act* provides for a price of carbon through an Output-Based Pricing System for industrial facilities and a fuel charge for non-exempt fossil fuel purchases, with the federal carbon price per tonne of carbon dioxide equivalent (CO^2e) emissions increasing by $15 per year, from $65 in 2023 to $170 in 2030. Ontario's Emissions Performance Standard program aligns with the federal carbon pricing. For OPG, compliance obligations for carbon pricing apply to the Lennox GS and Atura Power's combined cycle plants. OPG has implemented processes to recover carbon costs to the extent possible under the current revenue arrangements for these assets. As a result, the carbon pricing is not expected to have a material financial impact on the Company.

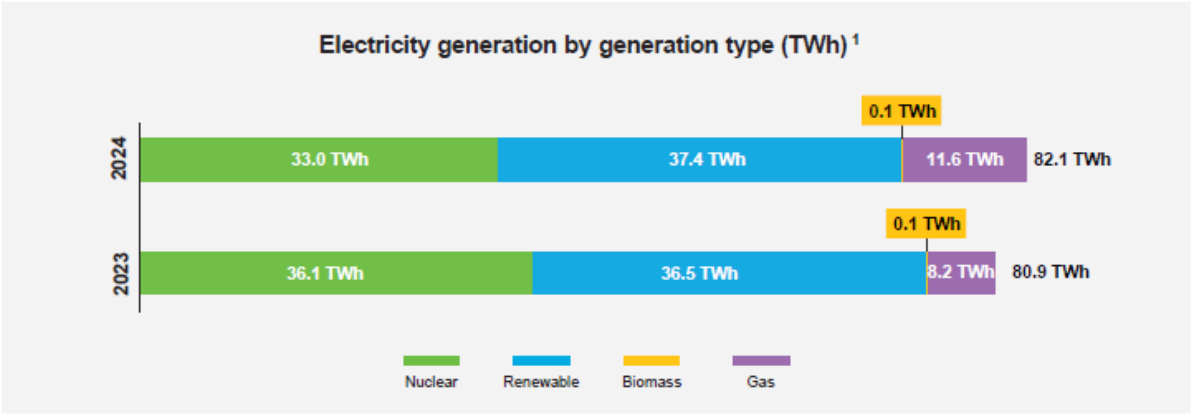
Climate-Related Performance and Key Metrics

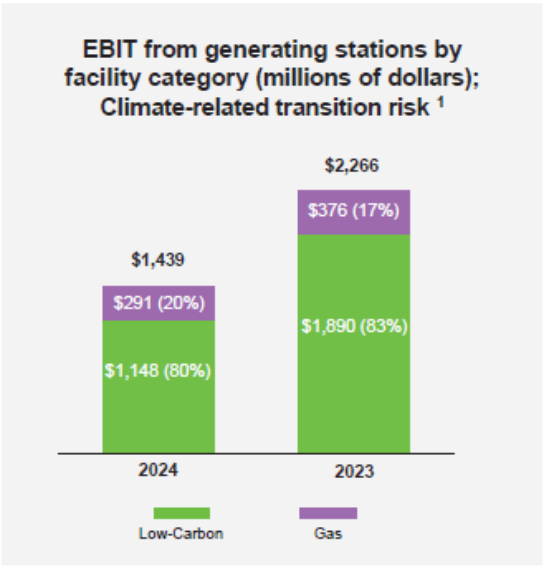
OPG continues to determine the most relevant climate-related impacts for the business in the context of its ESG and Sustainability framework and is engaged in aligning with industry metrics. OPG is in the process of developing such quantitative metrics and targets for climate change as part of an effort to integrate climate considerations into business processes. In the meantime, OPG has identified certain initial metrics that it considers relevant to stakeholders, which are as follows as at and for the years ended December 31:

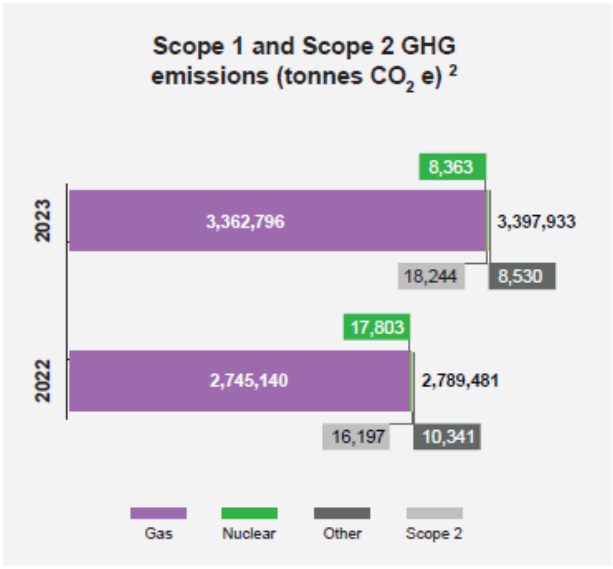
Climate Change Metrics











1 Includes OPG's proportionate share of in-service generating capacity and electricity generation from co-owned and minority-held facilities. Nuclear generating units undergoing refurbishment are excluded. Gas category includes the dual-fueled Lennox GS and the Company's combined cycle plants operated through Atura Power.

2 OPG continues to evaluate and enhance its Scope 1 and 2 GHG emission sources and quantification processes.

In-service generating capacity by generation type [1]	In-service generating capacity from low-carbon emitting and gas generation sources decreased as at December 31, 2024, compared to December 31, 2023. The decrease was primarily due to Unit 1 and Unit 4 of the Pickering GS ceasing commercial operation and being permanently taken offline on October 1, 2024, and December 31, 2024, respectively. The decrease was partially offset by Unit 1 of the Darlington GS returning to service from refurbishment on November 27, 2024. Low-carbon sources continue to account for the majority of OPG's total in-service generating capacity.
Electricity generation by generation type [2]	OPG's total electricity generation supplied by low-carbon sources for the year ended December 31, 2024 was approximately 86 percent of OPG's total electricity generation in 2024, compared to approximately 90 percent in 2023. The decrease in the percentage of generation from low-carbon sources was primarily due to lower electricity generation from the Regulated – Nuclear business segment as a result of higher planned and unplanned outage days at the Darlington GS and the cessation of commercial operation of Unit 1 of the Pickering GS, and from an increase in electricity generation from the Atura Power business segment due to higher demand for electricity generation from the combined cycle plants.
EBIT from generating stations by facility category; Climate-related transition risk [3]	Earnings before interest and income taxes from low-carbon electricity generation decreased in 2024, compared to 2023, primarily due to lower revenue from the Regulated – Nuclear Generation business segment and lower earnings from the Contracted Hydroelectric and Other Generation business segment. For further details, refer to the sections, *Regulated – Nuclear Generation Segment* and *Contracted Hydroelectric and Other Generation Segment* under the heading, *Discussion of Operating Results by Business Segment*.
Value and use of net proceeds from the green bond offerings	In June 2024, OPG's wholly-owned LME completed a private placement bond offering with the issuance of $200 million of green bonds, the net proceeds of which were used to refinance LME debt maturities in June 2024. OPG issued $1 billion of green bonds under its Medium Term Note Program in June 2024 and, in September 2024, re-opened these issuances for an additional $300 million. The net proceeds from these issuances were used to finance or re-finance Eligible Green Projects as defined under OPG's Sustainable Finance Framework. For further details, refer to the section, *Significant Developments* under the heading, *Financial Strength – Green Bonds*. OPG's Sustainable Finance Framework is available on the Company's website at www.opg.com.
Scope 1 GHG emissions – Direct and Emission Rate [4]	The Scope 1 GHG emissions metric identifies direct CO_2e emissions from OPG's thermal and nuclear operations and other facilities. For the year ended December 31, 2023, 3,362,796 tonnes of CO_2e (2022 – 2,745,140 tonnes of CO_2e) were emitted by thermal operations, representing over 99 percent of OPG's total CO_2e emissions, with the remainder emitted by nuclear operations and other facilities. The increase in CO_2e emissions in 2023 was primarily due to increased electricity generation from Atura Power's combined cycle plants. For the year ended December 31, 2023, OPG emitted CO_2e at an average rate of 41.7 grams per kilowatt-hour (kWh) of its total electricity generation (2022 – 35.3 grams per kWh).
Scope 2 GHG emissions – Indirect [4]	The Scope 2 GHG emissions metric identifies indirect CO_2e emissions from the purchase of energy from utility providers. For the year ended December 31, 2023, an estimated 18,244 tonnes of CO_2e (2022 – 16,197 tonnes of CO_2e) were emitted based on purchases of energy. The increase in CO_2e emissions in 2023 was primarily due to ongoing efforts to improve the GHG emissions inventory for this category.

1 Identifies capacity available from OPG's different generation sources and tracks low-carbon energy capacity relative to other sources. Nuclear, Renewable (which includes hydroelectric and solar) and Biomass (which uses wood pellets from sustainably managed forests) generation are considered to be low-carbon emitting generation sources.
2 Identifies electricity generated from OPG's different generation sources and tracks low-carbon energy generation sources (Nuclear, Renewable and Biomass) relative to other sources.
3 Identifies the portion of OPG's EBIT from electricity generating stations derived from low-carbon generation sources.
4 Scope 1 GHG emissions, Emission Rate and Scope 2 GHG emissions are reported annually.

Equity, Diversity and Inclusion

OPG is committed to workplace ED&I as part of a culture in which all employees, contractors and business partners are treated with fairness and respect. OPG recognizes that ED&I is integral to having a diverse, committed and agile workforce in a dynamic and changing industry, and is fundamental to achieving the Company's strategic goals.

With the support of its employees, host communities and business partners, the Company continues to advance its ED&I strategy and priorities, as follows:

- Accelerate equity – Ensure the Company's workforce is reflective of the communities it serves;
- Celebrate diversity – Celebrate employees with unique backgrounds, skills and characteristics; and
- Foster a culture of inclusion – Create inclusive cultures where everyone can connect, belong and grow.

The Company's commitment to ED&I underpins its 10-year ED&I Strategy and is reinforced through the Company's Code of Business Conduct and related governance. OPG's ED&I Strategy can be found on the Company's website www.opg.com.

In 2024, OPG received the Government of Canada's Employment Equity Achievement Award for Innovation. This award recognized OPG for achievement in implementing employment equity in the workplace, reflecting OPG's commitment to the Company's values of innovation and inclusion.

OPG continues to advance its ED&I commitment at the enterprise and site levels of the organization through comprehensive programming and support for local ED&I committees and employee resource groups across the province. These structures support ED&I policies, programs and initiatives, and facilitate employee engagement, feedback, networking opportunities, peer-to-peer discussion, and the promotion of ED&I awareness. During the third quarter of 2024, OPG completed a benchmarking exercise of its employee resource groups to better understand best practices and identify opportunities to enhance engagement and effectiveness of these structures.

OPG is committed to proactive employment practices to increase representation of the four designated groups under the *Employment Equity Act*. OPG uses metrics provided by Employment and Social Development Canada to assess progress and identify gaps between external availability and internal representation of the four designated groups. Labour market availability (LMA) calculations are based on data from Statistics Canada and the Canadian Survey on Disability, and are specific to OPG's industry, geographic locations and occupational categories. Under the *Employment Equity Act*, a workforce achieves employment equity when the internal representation of designated groups is equal to the relevant LMA.

OPG's workforce representation of these groups as at December 31 was as follows, compared to LMA:

Designated Group [1]	Labour Market Availability [2]	2024 [3]	2023 [3]
Women	27.7%	**24.6%**	24.0%
Indigenous Peoples	2.3%	**2.5%**	2.1%
Racialized People	23.9%	**22.9%**	19.3%
Persons with Disabilities	8.5%	**7.2%**	6.2%

[1] OPG's workforce representation values depend on employees voluntarily self-identifying.
[2] The LMA values shown are from 2023, as 2024 LMA data is not yet available.
[3] In 2024, workforce representation values were expanded to include temporary employees. For comparability, 2023 workforce representation values have been updated to also include temporary employees.

During 2024, OPG's continued to advance proactive employment equity initiatives that support the recruitment and advancement of designated group members, and conducted targeted outreach to increase the employees' response rate on OPG's employment equity workforce census. These efforts contributed to an increase in the overall workforce representation for the four designated groups in 2024, compared to 2023. OPG recognizes that representation gaps exist at various job levels and is committed to continuing to build a workforce that is reflective of the communities it serves across the organization.

OPG applies ED&I principles to succession planning and metrics to ensure candidate pools for management positions are diverse and equitable. Representation of designated groups at the Board and senior management level as of December 31, 2024 was as follows:

	Women		Total
Directors	**6**	**54.5%**	**11**
Diverse Directors [1]			**>50%**
Corporate Officers [2]	**4**	**44.4%**	**9**
Enterprise Leadership Team [3]	**6**	**54.5%**	**11**
Senior Leadership Team [4]	**25**	**34.7%**	**72**

[1] Under the *Canada Business Corporations Act* definition, OPG's Directors include three individuals who are members of more than one of the four designated groups.
[2] OPG management designated as corporate officers as defined by the *Business Corporations Act* (Ontario).
[3] Enterprise Leadership Team (ELT) comprises the OPG President and CEO, C-Suite Officers and Senior Vice Presidents who report directly to the CEO or who may be named to the ELT.
[4] In 2024, Senior Leadership Team values were expanded to include vice presidents, or equivalent, who do not report directly to a member of the ELT.

Indigenous Relations

OPG owns and operates electricity generation assets within the treaty and traditional territories of Indigenous peoples across Ontario. OPG's Indigenous Relations Policy and Reconciliation Action Plan formalize the Company's commitment to working with Indigenous communities to foster positive and mutually beneficial relationships that will create social and economic benefits through partnership and collaboration. OPG seeks to establish these relationships based on a foundation of respect, transparency and mutual responsibility. OPG's commitment in the area of Indigenous relations includes, where appropriate, pursuing generation-related development partnerships on the basis of long-term commercial arrangements and other joint projects proximate to the Company's present and future operations. OPG maintains a certified Gold Designation under the Canadian Council for Indigenous Business' Partnership Accreditation in Indigenous Relations program, which recognizes OPG as a national best-practices organization with a demonstrated commitment in the area of Indigenous relations. OPG's Reconciliation Action Plan can be found on the Company's website www.opg.com.

The Company has partnered successfully with Indigenous communities in Ontario on the construction of the Peter Sutherland Sr. hydroelectric GS project, the Lower Mattagami River hydroelectric project, the Lac Seul hydroelectric GS and the Nanticoke solar facility. The following table provides aggregate statistics related to these generation-related development partnerships for the years ended December 31:

Indigenous partnerships data	**2024**	**2023**
In-service generating capacity constructed in partnership with Indigenous communities *(MW)*	**574**	574
Electricity generation revenues earned in partnership with Indigenous Communities *(millions of dollars)*	**263**	261

OPG continues to undertake proactive and ongoing engagement with Indigenous communities in relation to the Company's operations and projects, including the following:

- On May 25, 2024, OPG delivered a formal apology to Wahnapitae First Nation (WFN) leadership and community members for historical impacts created when the Wanapitei Lake Dam was built, more than 100 years ago. The apology ceremony was part of a past grievance resolution process which OPG and WFN concluded with the signing of a final settlement agreement (FSA) in 2013. As part of the FSA, OPG and WFN were to complete shoreline protection in the community before the apology was delivered; and
- OPG is actively engaged with multiple Indigenous Nations and communities that have Aboriginal, Treaty and Inherent rights or interests on the lands and territories on which the DNNP is located. Twice monthly meetings took place throughout 2024 to ensure the First Nations with recognized Treaty Rights had access to information and were able to impact the project outcomes.

Increasing access to employment and procurement opportunities for Indigenous Peoples remains a key commitment in OPG's Reconciliation Action Plan. Central to this effort is OPG's Indigenous Opportunities Network (ION) program, which completed its seventh year in 2024. The program, a collaboration between OPG, the Electrical Power Systems Construction Association (EPSCA), Kagita Mikam Aboriginal Employment and Training, unions, and vendors engaged on the Darlington Refurbishment project, places Indigenous participants in energy sector building trades, such as carpenters, boilermakers, and millwrights.

In 2024, OPG initiated a cross-functional process to develop a new ION Strategy to identify areas of success and opportunities for growth, informed by feedback from former program participants, Indigenous communities and stakeholders as well as industry trends. As of December 31, 2024, the ION program exceeded its annual target by 10 percent, with 55 ION participants placed into employment roles. Since the program was launched in 2018, a total of 180 ION participants have been placed into employments roles.

OPG continues to focus on increasing opportunities for Indigenous businesses to participate in the Company's supply chain through competitive procurement processes. Over the course of 2024, OPG awarded approximately $170 million in such contracts to Indigenous businesses and partnerships. Since the launch of OPG's Reconciliation Action Plan in 2021, OPG has awarded approximately $370 million in contracts to Indigenous businesses, representing approximately 37 percent of the Company's commitment to generate $1 billion in economic impact with Indigenous businesses and communities over a 10-year period.

BUSINESS SEGMENTS

As at December 31, 2024, OPG had the following five reportable business segments:

- Regulated – Nuclear Generation;
- Regulated – Nuclear Sustainability Services;
- Regulated – Hydroelectric Generation;
- Contracted Hydroelectric and Other Generation; and
- Atura Power.

Regulated – Nuclear Generation Segment

The Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the Darlington and Pickering nuclear generating stations, both owned and operated by OPG. The business segment also includes revenue under the terms of a long-term lease arrangement and related non-lease agreements with Bruce Power related to the Bruce nuclear generating stations. This includes lease revenue, fees for nuclear waste management services, and revenue from heavy water sales and detritiation services. The segment also earns revenue from regulated isotope sales contracts and from supplying ancillary services to the electricity system from the nuclear generating stations operated by OPG. Additionally, the segment includes expenditures related to the development of SMRs at the DNNP site as these SMRs are prescribed for rate regulation by the OEB.

Regulated – Nuclear Sustainability Services Segment

OPG's Regulated – Nuclear Sustainability Services business segment reports the results of the Company's operations associated with the management of used nuclear fuel and L&ILW, the decommissioning of OPG's nuclear generating stations including the stations on lease to Bruce Power and other facilities, the management of the Nuclear Segregated Funds, and related activities including the inspection and maintenance of the used nuclear fuel and L&ILW storage facilities. Accordingly, accretion expense, which is the increase in the Nuclear Liabilities carried on the consolidated balance sheets in present value terms due to the passage of time, and earnings from the Nuclear Segregated Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs incremental costs related to used nuclear fuel and L&ILW, which increase the Nuclear Liabilities. OPG charges these incremental costs to current operations in the Regulated – Nuclear Generation business segment to reflect the cost of producing energy from the Darlington and Pickering nuclear generating stations and earning revenue under the Bruce Power lease arrangement and related agreements. Since the incremental costs increase the Nuclear Liabilities reported in the Regulated – Nuclear Sustainability Services business segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Sustainability Services business segments. The impact of the inter-segment charge is eliminated in the consolidated statements of income and balance sheets.

The Regulated – Nuclear Sustainability Services business segment is considered regulated because OPG's costs associated with the Nuclear Liabilities are included in the OEB's determination of regulated prices for electricity produced from the Darlington and Pickering nuclear generating stations.

Regulated – Hydroelectric Generation Segment

OPG's Regulated – Hydroelectric Generation business segment operates in Ontario, generating and selling electricity from most of the Company's hydroelectric generating stations. The business segment comprises the results of 54 regulated hydroelectric generating stations located across a number of major river systems in the province. Additionally, the business segment includes revenues from supplying ancillary services to the electricity system and other revenues from OPG's regulated hydroelectric stations.

Contracted Hydroelectric and Other Generation Segment

The Contracted Hydroelectric and Other Generation business segment operates in Ontario and in the US, generating and selling electricity from the Company's non-regulated generating stations. The segment primarily includes generating facilities that operate under ESAs with the IESO. The majority of the generating facilities in the US currently supply energy and capacity into wholesale electricity markets.

The Contracted Hydroelectric and Other Generation business segment includes OPG's share of equity income from co-owned and minority-held non-regulated electricity generating facilities, and revenues from supplying ancillary services to the electricity system and other revenues from the stations included in the segment.

Atura Power Segment

The Atura Power business segment operates in Ontario, generating and selling electricity from the Company's fleet of combined cycle generating stations. All of the generating facilities included in the segment operate under ESAs with the IESO. The segment also includes revenues from participation in the IESO's operating reserve markets and generation cost guarantee programs. Additionally, the segment includes Atura Power's expenditures on development projects, including low-carbon hydrogen production, battery energy storage systems and combined cycle plant expansion.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

(millions of dollars – except where noted)	**2024**	**2023**
Electricity generation (TWh)	**33.0**	36.1
Revenue	**3,798**	4,277
Fuel expense	**288**	269
Gross margin	**3,510**	4,008
Operations, maintenance and administration expenses	**2,474**	2,410
Property taxes	**25**	25
Other losses	**9**	-
Earnings before interest, income taxes, depreciation and amortization	**1,002**	1,573
Depreciation and amortization expenses	**665**	527
Earnings before interest and income taxes	**337**	1,046

Earnings before interest and income taxes from the segment decreased by $709 million in 2024, compared to 2023.

The decrease in segment earnings was primarily due to lower revenue of $324 million driven by lower electricity generation of 3.1 TWh, and a decrease in revenue of $146 million from a lower OEB-approved nuclear base regulated price in effect during 2024.

Higher OM&A expenses of $64 million and lower amounts deferred in the Rate Smoothing Deferral Account of $64 million also contributed to the lower segment earnings. The higher OM&A expenses were primarily due to higher expenditures related to the cyclical maintenance activities and other planned maintenance work executed as a result of higher planned outage days at the Darlington GS, partially offset by lower expenses due to fewer planned outage days at the Pickering GS. The decrease in segment earnings was partially offset by a higher amount of $48 million recorded as recoverable from customers in the Pickering B Extension Variance Account in connection with forgone electricity generation due to activities associated with the extension of commercial operation of Units 5 to 8 of the Pickering GS to September 2026, prior to the planned refurbishment.

Increased compensation expenses in 2024 resulting from the ratification of a three-year renewal collective agreement between the PWU and OPG in November 2024 were offset by the higher compensation expenses recognized in 2023 related to the impact on OPG's collective agreements from the Bill 124 Court Decision and the OEB's subsequent decisions issued in 2023 that denied OPG's request for a regulatory variance account to record these cost impacts.

The higher depreciation and amortization expenses of $101 million in 2024, compared to 2023, excluding amortization expense related to the recovery and repayment of OEB-authorized regulatory account balances, were primarily due to higher depreciation expense recognized from placing capital in service, including the return to service of Unit 3 and Unit 1 of the Darlington GS following refurbishment in July 2023 and November 2024, respectively, and lower amounts of depreciation expense recorded as recoverable from customers through regulatory accounts.

An increase in revenue in 2024 reflecting the impact of the new rate riders for disposition of regulatory accounts under the OEB's June 2024 decision and order approving the 2024 Settlement Agreement, effective July 1, 2024, was largely offset by a corresponding increase in the amortization expense of regulatory assets and regulatory liabilities recorded for regulatory account balances.

The planned and unplanned outage days at the Darlington and Pickering nuclear generating stations were as follows:

	2024	2023
Planned Outage Days		
Darlington GS [1]	**118.3**	11.8
Pickering GS	**295.6**	371.2
Unplanned Outage Days		
Darlington GS [1]	**88.3**	20.9
Pickering GS	**76.6**	76.1

[1] The planned and unplanned outage days exclude unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 3 and Unit 1 of the Darlington GS were excluded from the reported planned and unplanned outage days during their refurbishment periods of September 3, 2020 to July 17, 2023, and February 15, 2022 to November 27, 2024, respectively. Unit 4 of the Darlington GS has been excluded from the measure since commencing refurbishment on July 19, 2023.

The higher planned outage days at the Darlington GS during 2024, compared to 2023, were driven by the impact of the station's cyclical maintenance schedule and other planned maintenance work executed on the station's Unit 2 in the first half of the year.

The lower planned outage days at the Pickering GS during 2024, compared to 2023, were driven by the impact of the station's cyclical maintenance schedule and other planned maintenance work executed at the station in 2023.

The higher unplanned outage days at the Darlington GS during 2024, compared to 2023, were primarily due to non-routine turbine generator maintenance activities on the station's Unit 2 in the fourth quarter of 2024 and steam generator repair activities on the station's Unit 3 during the first half of 2024.

The unplanned outage days at the Pickering GS during 2024 were comparable to 2023.

The Unit Capability Factors for the Darlington and Pickering nuclear generating stations were as follows:

	2024	2023
Unit Capability Factor *(%)* [1, 2]		
Darlington GS	**74.6**	97.0
Pickering GS	**83.3**	80.7

[1] Nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment.
[2] Nuclear Unit Capacity Factor is defined in the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*.

The Unit Capability Factor at the Darlington GS decreased in 2024, compared to 2023, primarily due to a higher number of planned and unplanned outage days. The higher Unit Capability Factor at the Pickering GS in 2024, compared to 2023, was due to fewer planned outage days.

Regulated – Nuclear Sustainability Services Segment

(millions of dollars – except where noted)	**2024**	**2023**
Revenue	**185**	203
Operations, maintenance and administration expenses	**185**	203
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**1,210**	1,167
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(1,102)**	(1,057)
Loss before interest and income taxes	**(108)**	(110)

The segment loss before interest and income taxes decreased by $2 million in 2024 compared to 2023. The decrease was primarily due to higher earnings on the Nuclear Segregated Funds, largely offset by higher accretion expense on the Nuclear Liabilities. The higher accretion expense on the Nuclear Liabilities was due to the increase in the present value of the underlying obligation to reflect the passage of time.

The higher earnings from the Nuclear Segregated Funds were primarily due to the growth in the present value of the underlying funding liabilities per the approved ONFA reference plan in effect. As both the Decommissioning Segregated Fund and the Used Fuel Segregated Fund were in an overfunded position during both 2024 and 2023, they were not impacted by market returns or the rate of return guarantee provided by the Province for a portion of the Used Fuel Segregated Fund. When both funds are in an overfunded position, OPG limits the amount of Nuclear Segregated Funds assets reported on the consolidated balance sheet to the present value of the underlying funding liabilities per the approved ONFA reference plan in effect. Further details on the accounting for the Nuclear Segregated Funds can be found in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

Regulated – Hydroelectric Generation Segment

(millions of dollars – except where noted)	**2024**	**2023**
Electricity generation (TWh)	**32.5**	31.4
Revenue [1]	**1,571**	1,485
Fuel expense	**335**	327
Gross margin	**1,236**	1,158
Operations, maintenance and administration expenses	**413**	391
Property tax	**1**	1
Other losses	**11**	9
Earnings before interest, income taxes, depreciation and amortization	**811**	757
Depreciation and amortization expenses	**227**	181
Earnings before interest and income taxes	**584**	576

[1] During 2024 and 2023, the Regulated – Hydroelectric Generation business segment revenue included incentive payments of $28 million and $15 million, respectively, related to the OEB-approved hydroelectric incentive mechanism. The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

Earnings before interest and income taxes from the segment increased by $8 million in 2024, compared to 2023. The increase in segment earnings was mainly due to higher revenues, largely driven by fewer outages impacting production at the regulated hydroelectric generating stations in 2024 and higher hydroelectric incentive mechanism payments, which was partly offset by higher OM&A expenses, mainly driven by increased planned maintenance activities.

An increase in revenue in 2024 reflecting the impact of the new rate riders for disposition of regulatory accounts under the OEB's June 2024 decision and order approving the 2024 Settlement Agreement, effective July 1, 2024, was largely offset by a corresponding increase in the amortization expense of regulatory assets and regulatory liabilities recorded for regulatory account balances.

The Hydroelectric Availability for the generating stations reported in the Regulated – Hydroelectric Generation business segment was as follows:

	2024	**2023**
Hydroelectric Availability *(%)* [1]	**85.8**	85.4

[1] Hydroelectric Availability is defined in the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*.

The Hydroelectric Availability in 2024 was comparable to 2023.

Contracted Hydroelectric and Other Generation Segment

(millions of dollars – except where noted)	**2024**	**2023**
Electricity generation (TWh)	**5.0**	5.2
Revenue	**815**	815
Fuel expense	**59**	58
Gross margin	**756**	757
Operations, maintenance and administration expenses	**307**	274
Accretion on fixed asset removal liabilities	**9**	8
Property taxes	**18**	18
Other losses	**6**	4
Earnings before interest, income taxes, depreciation and amortization	**416**	453
Depreciation and amortization expenses	**174**	165
Earnings before interest and income taxes	**242**	288

Earnings before interest and income taxes from the segment decreased by $46 million in 2024, compared to 2023. The decrease was primarily due to lower earnings from the US operations, largely driven by OM&A expenses reflecting business development activities for community solar generation projects following the acquisition of Lightstar in January 2024, and higher depreciation and amortization expenses. The higher depreciation and amortization expenses were driven primarily by a depreciation adjustment recorded during the second quarter of 2024 in relation to the reclassification of certain US-based hydroelectric facilities from being held for sale to PP&E and intangible assets.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) within the Contracted Hydroelectric and Other Generation business segment were as follows:

	2024	**2023**
Hydroelectric Availability *(%)* [1, 2]	**80.8**	85.9
Thermal EFOR *(%)* [2]	**3.8**	1.8

[1] Hydroelectric Availability reflects hydroelectric generating stations in Ontario and the United States.
[2] Hydroelectric Availability and Thermal EFOR are defined in the section, Key Operating Performance Indicators and Non-GAAP Financial Measures.

The Hydroelectric Availability decreased in 2024, compared to 2023, primarily due to higher planned outages at the Lower Mattagami hydroelectric generating stations.

The Thermal EFOR increased in 2024, compared to 2023, primarily due to higher unplanned outages at the Lennox GS and the Atikokan GS.

Atura Power Segment

(millions of dollars – except where noted)	**2024**	**2023**
Electricity Generation (TWh)	**11.6**	8.2
Revenue	**871**	789
Fuel expense	**367**	320
Gross margin	**504**	469
Operations, maintenance and administration expenses	**98**	80
Accretion on fixed asset removal liabilities	**2**	2
Property taxes	**2**	3
Other losses (gains)	**1**	(93)
Earnings before interest, income taxes, depreciation and amortization	**401**	477
Depreciation and amortization expenses	**125**	121
Earnings before interest and income taxes	**276**	356

Earnings before interest and income taxes from the segment decreased by $80 million in 2024 compared to 2023. The decrease was primarily due to the release of a previously recognized contingent liability in the fourth quarter of 2023 under a 2021 settlement agreement related to an acquisition of combined cycle plants. The decrease was partially offset by higher gross margin as a result of higher demand for electricity generation from the combined cycle plants. The higher OM&A expenses were due to increased maintenance activities at the combined cycle plants.

The Thermal Availability for the assets within the Atura Power business segment was as follows:

	2024	**2023**
Thermal Availability *(%)* [1]	**86.4**	89.5

[1] Thermal Availability is defined in the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*. The measure reflects the availability of the combined cycle plants as at the year-end date, calculated on a three-year rolling average basis.

The Thermal Availability for the combined cycle plants decreased as at December 31, 2024, compared to December 31, 2023, primarily due to a planned outage at the Halton Hills GS.

LIQUIDITY AND CAPITAL RESOURCES

OPG maintains a range of funding sources to ensure sufficient liquidity and meet financing requirements. These sources are used for multiple purposes including: to invest in plants and technologies, undertake major projects and business acquisitions, fund long-term obligations such as contributions to the pension fund, make payments under the OPEB plans, fund expenditures on Nuclear Liabilities not eligible for reimbursement from the Nuclear Segregated Funds, service and repay long-term debt, and provide general working capital.

Changes in cash and cash equivalents for 2024 and 2023 were as follows:

(millions of dollars)	**2024**	**2023**
Cash, cash equivalents and restricted cash, beginning of period	**1,481**	1,595
Cash flow provided by operating activities	**2,211**	2,538
Cash flow used in investing activities	**(3,668)**	(2,969)
Cash flow provided by financing activities	**1,326**	320
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**13**	(3)
Net decrease in cash, cash equivalents and restricted cash	**(118)**	(114)
Cash and cash equivalents and restricted cash, end of period	**1,363**	1,481

For a discussion of cash flow provided by operating activities, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity and extend the operating life of existing stations, and to invest in the development of new generating facilities, emerging technologies and other business growth opportunities.

Cash flow used in investing activities increased by $699 million in 2024, compared to 2023, primarily due to higher capital expenditures, mainly within the Regulated – Nuclear Generation business segment, and the acquisition of Lightstar on January 31, 2024. The increase was partially offset by the purchase of the new corporate headquarters building and surrounding lands at 1908 Colonel Sam Drive in Oshawa, Ontario in February 2023.

Financing Activities

As at December 31, 2024, long-term debt outstanding was $11,707 million, with $604 million representing amounts due within one year. Short-term debt outstanding as at December 31, 2024 was $215 million.

Cash flow provided by financing activities increased by $1,006 million in 2024, compared to 2023, primarily due the issuance of $1.3 billion of green bonds through the Company's Medium Term Note Program during 2024. The increase was partially offset by higher repayments of long-term debt and lower net issuances of short-term debt during 2024.

Committed credit facilities and maturity dates as at December 31, 2024 were as follows:

(millions of dollars)		**Amount**
Bank facilities:		
Corporate [1, 2]		**1,211**
Corporate [1]	US Dollars	**750**
Lower Mattagami Energy Limited Partnership [3]		**460**
OPG Eagle Creek Holdings LLC and subsidiaries	US Dollars	**20**
Ontario Financing Authority facility [2]		**1,250**
Ontario Electricity Financial Corporation facility [2]		**750**

[1] Certain corporate credit facilities contain a sustainability-linked feature that allows reduced pricing if the Company meets certain sustainability targets.
[2] Represents amounts available under the facility net of debt issuances.
[3] Letter of credit of $60 million was outstanding under this facility as at December 31, 2024.

Short-term debt, letters of credit and guarantees as at December 31 were as follows:

(millions of dollars)	**2024**	**2023**
Lower Mattagami Energy Limited Partnership	**215**	200
Total short-term debt	**215**	200
Letters of credit	**504**	525
Guarantees [1]	**30**	32

[1] As at December 31, 2024, the potential impact of the fair value of the outstanding guarantees to income is $1 million and OPG does not expect to make any payments associated with these guarantees.

As of December 31, 2024, a total of $504 million of letters of credit had been issued. As of December 31, 2024, this included $314 million for the supplementary pension plans, $60 million for Lower Mattagami Energy Limited Partnership, $51 million for general corporate purposes, $45 million for Atura Power, $19 million for Eagle Creek and its subsidiaries, $14 million for UMH Energy Partnership, and $1 million for PSS Generating Station Limited Partnership.

Long-term debt balances as at December 31 were as follows:

(millions of dollars)	**2024**	**2023**
Medium Term Notes payable	**5,950**	4,650
Senior notes payable under OEFC and corporate credit facilities	**2,859**	2,822
Project financing	**2,916**	2,877
Other	**25**	25
Total Long-term debt [1]	**11,750**	10,374

[1] Excludes the impact of fair value premium and unamortized bond issuance fees.

Further details on financing activities during the year can be found in the section, *Significant Developments* under the heading, *Financial Strength*.

Share Capital

As at December 31, 2024 and 2023, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value. Any issue of new shares is subject to the consent of OPG's shareholder, the Province.

As at December 31, 2024 and 2023, OPG had 18,343,815 Class A shares issued and outstanding at a stated value of $787 million. OPG is entitled to redeem outstanding Class A shares as may be approved by OPG's Board.

Contractual Obligations

OPG's contractual obligations as at December 31, 2024 were as follows:

(millions of dollars)	2025	2026	2027	2028	2029	Thereafter	Total
Fuel supply agreements	218	186	172	143	109	343	1,171
Contributions to the OPG registered pension plan [1]	125	128	-	-	-	-	253
Long-term debt repayment	604	674	530	269	505	9,168	11,750
Interest on long-term debt	439	421	410	392	379	5,153	7,194
Short-term debt repayment	215	-	-	-	-	-	215
Commitments related to Darlington Refurbishment project [2]	163	-	-	-	-	-	163
Commitments related to Atura Power development projects [2]	503	132	-	16	-	-	651
Commitments related to Pickering Refurbishment project and DNNP [2]	229	-	-	-	-	-	229
Operating licences	57	57	64	62	51	105	396
Operating lease obligations	15	14	11	4	3	36	83
Accounts payable, accrued charges and other payables	1,890	9	10	9	10	278	2,206
Other	50	71	49	33	20	89	312
Total	4,508	1,692	1,246	928	1,077	15,172	24,623

[1] Represents the estimated pension contributions consistent with the period covered by the actuarial valuation of the OPG registered pension plan as at January 1, 2024. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2027. Funding requirements after January 1, 2027 are excluded due to significant variability in the assumptions required to project the timing of future cash flows.

[2] Represents estimated currently committed costs to close the projects, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Ontario Nuclear Funds Agreement

Pursuant to the ONFA, OPG may be required to make contributions to the Nuclear Segregated Funds, based on life cycle cost estimates and resulting funding liabilities for nuclear facilities decommissioning and nuclear waste management, determined under periodically updated reference plans as approved by the Province. Based on the 2022 ONFA Reference Plan approved by the Province, OPG is currently not required to make overall contributions to the Nuclear Segregated Funds. Contributions may be required in the future should the Nuclear Segregated Funds be in an underfunded position at the time of the next ONFA reference plan update, which is scheduled to be completed at the end of 2026. Such may be the case as a result of variability in fund asset performance due to volatility inherent in financial markets and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province, changes in the Ontario CPI, as well as changes in funding liability estimates.

Further details on the Nuclear Segregated Funds can be found in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

Collective Agreements

As at December 31, 2024, OPG and its wholly-owned subsidiaries had approximately 11,030 regular and term-based employees (regular workforce), mostly in Ontario. Pursuant to collective agreements, term-based unionized employees may be hired in place of regular unionized employees for positions likely to be eliminated as a result of the shutdown of the Pickering GS units. Most of OPG's regular workforce in Ontario is represented by two unions:

- PWU – As at December 31, 2024, this union represented approximately 5,180 regular and term-based employees, or 47 percent of OPG and its subsidiaries' regular workforce. Union membership includes station operators, technicians, skilled trades, clerical staff and security personnel. On November 20, 2024, the PWU membership ratified a three-year renewal collective agreement negotiated by the parties, covering the period from April 1, 2024 to March 31, 2027.

  Additionally, there are two collective agreements between the PWU and Atura Power, and a collective agreement between the PWU and LEP. On July 19, 2024, a two-year renewal collective agreement expiring on November 16, 2025 was ratified by the PWU-represented employees at the Brighton Beach GS. The governing collective agreement covering PWU-represented employees at Atura Power's other facilities expired on December 31, 2024, and negotiations for a renewal collective agreement are ongoing. The governing two-year collective agreement between PWU and LEP expired on February 28, 2025, and negotiations for a renewal collective agreement are ongoing.

- Society – As at December 31, 2024, this union represented approximately 4,000 regular and term-based employees, or 36 percent of OPG and its subsidiaries' regular workforce. Union membership includes supervisors, professional engineers, scientists and other professionals. The current two-year collective agreement between the Society and OPG expires on December 31, 2025.

  In June 2023, the Society filed a related employer application with the Ontario Labour Relations Board. The application identified OPG and Atura Power as responding parties and asserted that they constitute a single employer for purposes of the Ontario *Labour Relations Act, 1995*, or in the alternative that a sale of business has occurred. Both OPG and Atura Power are opposing the application. Discussions are ongoing between the parties and two additional hearing dates have been scheduled in September 2025.

In addition, construction work in Ontario is performed through craft unions with established bargaining rights at OPG facilities. These bargaining rights are established either through the EPSCA or directly with OPG or its wholly-owned subsidiaries. The associated collective agreements are negotiated either directly between the parties or through the EPSCA, as applicable. Most of these collective agreements currently have multi-year terms that expire on April 30, 2025. Negotiations for the renewal of such collective agreements are ongoing, with 11 agreements finalized, one pending ratification, and nine agreements pending negotiations. All renewal agreements are expected to have five-year terms covering the period from May 1, 2025 to April 30, 2030. EPSCA is a voluntary association of owners and contractors who perform work in Ontario's electrical power systems sector.

BALANCE SHEET HIGHLIGHTS

The following section provides other highlights of OPG's 2024 audited consolidated financial position using selected balance sheet data as at December 31:

(millions of dollars)	**2024**	**2023**
Property, plant and equipment – net The increase was primarily due to capital expenditures during the year, partially offset by depreciation expense. Further details on capital expenditures can be found in the section, Highlights under the heading, *Capital Expenditures.*	**36,131**	33,460
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)* The increase was primarily due to earnings recognized on the Nuclear Segregated Funds, partially offset by reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities from the Nuclear Segregated Funds.	**22,412**	21,563
Long-term debt *(current and non-current portions)* The increase was primarily due to issuances under the Company's Medium Term Note Program and corporate credit facilities, net of debt repayments to the OEFC.	**11,707**	10,342
Fixed asset removal and nuclear waste management liabilities The increase was primarily a result of accretion expense, partially offset by expenditures on fixed asset removal and nuclear waste management activities.	**26,042**	25,386
Pension liabilities The decrease was primarily due to the excess of actual returns on pension plan assets over interest costs on the liabilities during 2024 and the remeasurement of the liabilities at the end of 2024 reflecting higher discount rates.	**46**	883

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's consolidated financial statements or are recorded in the Company's consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

Guarantees

As part of normal business, OPG and certain of its subsidiaries and joint ventures enter into various agreements to provide financial or performance assurance to third parties. Such agreements include guarantees, standby Letters of Credit and surety bonds.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies, including the impact of major recent accounting pronouncements, are outlined in Note 3 of OPG's 2024 audited consolidated financial statements. Certain of these policies are recognized as critical accounting policies by virtue of the subjective and complex judgments and estimates required around matters that are inherently uncertain and could result in materially different amounts being reported under different conditions or assumptions. The critical accounting policies and estimates that affect OPG's US GAAP consolidated financial statements are highlighted below.

Exemptive Relief for Reporting under US GAAP

In September 2022, OPG received an extension to its exemptive relief from the OSC requirements of section 3.2 of National Instrument 52-107 – *Acceptable Accounting Policies and Auditing Standards*. The exemption allows OPG to file consolidated financial statements based on US GAAP, rather than IFRS, without becoming a Securities and Exchange Commission registrant. This exemption replaced the previous exemptive relief received by OPG from the OSC in April 2018. The exemption will terminate on the earliest of the following:

- January 1, 2027;
- The financial year that commences after OPG ceases to have activities subject to rate regulation; and
- The financial year that commences on or following the later of:
    I. The effective date prescribed by the International Accounting Standards Board (IASB) for the mandatory application of a standard within IFRS specific to entities with rate regulated activities (Mandatory Rate-regulated Standard); and
    II. Two years after the IASB publishes the final version of a Mandatory Rate-regulated Standard.

The IASB's current standard-setting project related to entities with rate-regulated activities is ongoing.

Rate Regulated Accounting

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that OPG receives regulated prices for electricity generated from the 54 prescribed hydroelectric generating stations and the Darlington and Pickering nuclear generating stations located in Ontario. OPG's regulated prices for these facilities are determined by the OEB.

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998*, the *Electricity Act, 1998* and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Ontario Ministry of Energy and Electrification. It regulates market participants in Ontario's natural gas and electricity industries. The OEB carries out its regulatory functions through public hearings and other more informal processes such as consultations.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required by the regulator to be obtained from, or settled with, the customers. When the Company assesses that there is sufficient assurance that incurred costs in respect of the regulated facilities will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the Company is required to refund amounts to customers in the future in respect of the regulated facilities, including amounts related to costs that have not been incurred and for which the OEB has provided recovery through regulated prices, the Company records a regulatory liability.

Certain regulatory assets and regulatory liabilities recognized by the Company relate to regulatory accounts authorized by the OEB, or *Ontario Regulation 53/05*. The measurement of these regulatory assets and regulatory liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

Regulatory assets and regulatory liabilities for regulatory account balances approved by the OEB for inclusion in regulated prices are amortized based on approved recovery or repayment periods.

In addition to regulatory assets and regulatory liabilities for regulatory accounts, OPG recognizes regulatory assets and regulatory liabilities for unamortized amounts recorded in accumulated other comprehensive income or loss (AOCI) in respect of pension and OPEB obligations, deferred income taxes, and, as applicable, differences between interim regulated prices charged to customers during an interim rate period and final regulated prices authorized or to be authorized by the OEB for that period, to reflect the expected recovery or repayment of these amounts through future regulated prices to be charged to customers. There are measurement uncertainties related to these balances due to the assumptions made in the determination of pension and OPEB obligations and deferred income taxes that are attributed to the regulated business segments, and assumptions made with respect to final regulated prices to be authorized by the OEB for an interim rate period.

The regulatory assets and regulatory liabilities recognized by the Company for unamortized pension and OPEB amounts recorded in AOCI has reflected the OEB's use, since April 1, 2008, of the accrual basis of accounting for including pension and OPEB amounts in approved regulated prices for OPG. This is also the manner in which these costs are recognized in OPG's audited consolidated financial statements. Therefore, unamortized amounts in respect of OPG's pension and OPEB plans recognized in AOCI generally would not be reflected in regulated prices until they have been reclassified from AOCI and recognized as amortization components of the benefit costs for these plans. The regulatory assets and regulatory liabilities are reduced as underlying unamortized balances are amortized as components of the benefit cost.

For the period from November 1, 2014 to December 31, 2021, the OEB limited amounts for pension and OPEB costs included in the nuclear and hydroelectric regulated prices to the respective regulated business' portions of the Company's cash expenditures for its pension and OPEB plans. The differences between actual pension and OPEB costs determined using the accrual method applied in OPG's audited consolidated financial statements and OPG's actual cash expenditures for these plans were captured in the OEB-authorized Pension & OPEB Cash Versus Accrual Differential Deferral Account for future consideration by the OEB.

In 2017, the OEB issued a report outlining the guiding principles and policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report established the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility.

The OEB's February 2019 decision and order approving the proposed settlement reached by OPG and intervenors on OPG's August 2018 application to disposition regulatory accounts resulted in approval to recover the balance recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account as of December 31, 2017, without adjustments. In making that decision and order, the OEB approved that the accrual method was the appropriate regulatory accounting and cost recovery basis for the December 31, 2017 pension and OPEB-related balances in the Pension & OPEB Cash Versus Accrual Differential Deferral Account.

The 2021 Settlement Agreement provided for recovery of pension and OPEB costs in the nuclear revenue requirements using the accrual method of accounting, with the differences between actual pension and OPEB costs determined using such method and corresponding forecast amounts reflected in the approved revenue requirements to be recorded in the Pension and OPEB Cost Variance Account for subsequent review and approval by the OEB. For the hydroelectric facilities, the Pension & OPEB Cash Versus Accrual Differential Deferral Account continues to record the differences between actual pension and OPEB costs determined using the accrual method and actual cash expenditures for these plans. The 2021 Settlement Agreement and the 2024 Settlement Agreement provided for recovery of the balance recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account as of December 31, 2019 and December 31, 2022, respectively, without adjustments.

It is the Company's position that the above outcomes have collectively established the accrual basis of accounting as the default method of determining pension and OPEB amounts for rate-setting purposes and that there is sufficient likelihood that unamortized pension and OPEB amounts that have not yet been reclassified from AOCI, as well as amounts recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account subsequent to

December 31, 2022 will be included in future regulated prices. Therefore, the Company continues to recognize regulatory assets and regulatory liabilities for these balances.

Useful Lives of Long-Lived Assets

The accounting estimates related to end-of-life assumptions for PP&E and intangible assets require significant management judgment, including consideration of various operating, technological and economic factors. OPG reviews the estimated useful lives for its PP&E and intangible assets, including end-of-life assumptions for major generating assets, on a regular basis. Major nuclear station components are depreciated over the lesser of the station life and the life of the components.

For nuclear generating stations operated by OPG, establishing station end-of-life assumptions primarily involves an assessment of operating lives of major life-limiting components such as fuel channel assemblies, taking into account expectations of future ability to economically operate and as appropriate refurbish the station for continued use. Expected operating lives of major life-limiting components are established through technical assessments of their fitness-for-service. Expectations of future ability to operate the station may be affected by operating licence requirements, ability to recover capital, operating and decommissioning costs and government policy, among other factors.

Although there is a link between the age of a hydroelectric generating facility and the capital investment required to maintain that facility, age does not generally establish an overall upper limit on the expected useful life of a hydroelectric generating station. Regular maintenance and the replacement of specific components typically allow hydroelectric stations to operate for very long periods. An estimated useful life not exceeding 100 years is used by OPG to depreciate dams and other major hydroelectric station structures.

Station end-of-life assumptions for thermal and solar generating assets are established based on operating life expectations of major components and expectations of future ability to economically operate the facility taking into consideration available revenue mechanisms.

Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the fair value of the assets acquired and liabilities assumed.

The Company allocates goodwill to operating segments that are expected to benefit from the goodwill recognized. At least once a year, the Company assesses qualitative and quantitative factors to determine whether it is more likely than not that the fair value of a reporting unit to which goodwill is attributed is less than its carrying amount. If it is more likely than not that a reporting unit's fair value is less than its carrying amount or if a quantitative assessment is elected, the Company calculates the fair value of the reporting unit. The carrying amount of a reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit exceeds its fair value. Any impairment charge represents the excess of the reporting unit's carrying amount over its fair value, to the extent that the impairment charge is limited to the total amount of goodwill allocated to the reporting unit. Goodwill is tested for impairment between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

In accordance with the ONFA, OPG sets aside and invests funds that are held in segregated custodian and trustee accounts specifically for discharging its life cycle obligation for nuclear decommissioning and long-term nuclear waste management in connection with the existing facilities. The Decommissioning Segregated Fund was established to fund the future costs of nuclear fixed asset removal and long-term L&ILW management, and certain costs of used nuclear fuel storage incurred after the nuclear generating stations are shut down. The Used Fuel Segregated Fund was established to fund the future costs of long-term used nuclear fuel management and certain costs of used nuclear fuel storage incurred after the nuclear generating stations are shut down. Costs for interim management of L&ILW and used

nuclear fuel storage incurred during respective station operation are not generally reimbursed from the Nuclear Segregated Funds. Such costs are funded through the Company's operating cash flow or other sources of liquidity. The Ontario NFWA Trust (NFWA Trust), a trust fund established by OPG as an owner of used nuclear fuel to fund certain long-term used nuclear fuel management costs pursuant to the *Nuclear Fuel Waste Act* (Canada), forms part of the Used Fuel Segregated Fund, with any portion of the fund not in the NFWA Trust being able to be applied towards the NFWA Trust's annual contribution requirements.

Decommissioning Segregated Fund

Upon termination of the ONFA, the Province has the sole right to any excess funds in the Decommissioning Segregated Fund. Accordingly, when the Decommissioning Segregated Fund is overfunded, OPG limits the fund earnings it recognizes in the consolidated financial statements by recording an amount due to the Province, such that the fund asset recognized on the consolidated balance sheet is equal to the cost estimate of the liability based on the most recently approved ONFA reference plan. Additionally, OPG recognizes the portion of the surplus that it may direct to the Used Fuel Segregated Fund, which is possible when the surplus is such that the underlying liabilities, as defined by the most recently approved ONFA reference plan, are at least 120 percent funded. In those circumstances, OPG may direct, at the time a new or amended reference plan is approved, up to 50 percent of the surplus over 120 percent to the Used Fuel Segregated Fund, with the OEFC being entitled to a distribution of an equal amount. Therefore, when the Decommissioning Segregated Fund is at least 120 percent funded, OPG recognizes 50 percent of the excess greater than 120 percent in income, up to the amount by which the Used Fuel Segregated Fund is underfunded.

The amount due to the Province in respect of the Decommissioning Segregated Fund could be reduced in subsequent periods in the event that the fund earns less than its target rate of return, a new or amended ONFA reference plan is approved with a higher underlying funding liability, or the amount of the underfunding, if any, in the Used Fuel Segregated Fund increases.

When the Decommissioning Segregated Fund is underfunded, the earnings on the fund reflect actual fund returns based on the market value of the fund assets.

Used Fuel Segregated Fund

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Segregated Fund at 3.25 percent plus the change in the Ontario CPI, as defined in the ONFA, for funding related to the first 2.23 million used nuclear fuel bundles (committed return). OPG recognizes the committed return on the Used Fuel Segregated Fund as earnings on the Nuclear Segregated Funds. The difference between the committed return and the actual market return determined based on the fair value of the fund assets related to the first 2.23 million used nuclear fuel bundles is recorded as due to or due from the Province. This amount represents the amount OPG would pay to, or receive from, the Province if the committed return were to be settled as of the consolidated balance sheet date. Upon approval of a new or amended ONFA reference plan, the Province is obligated to make an additional contribution to the Used Fuel Segregated Fund in relation to the first 2.23 million used nuclear fuel bundles if the fund assets earned a rate of return that is less than the guaranteed rate of return. If the return on the fund assets exceeded the Province's guaranteed rate of return, the Province is entitled to withdraw any portion of such excess related to the first 2.23 million used nuclear fuel bundles, upon approval of a new or amended ONFA reference plan. The 2.23 million threshold represents the number of estimated total life cycle fuel bundles based on the initial estimated useful lives of the nuclear generating stations assumed in the ONFA.

As prescribed under the ONFA, OPG's contributions attributed to the used nuclear fuel bundles in excess of the first 2.23 million are not subject to the rate of return guaranteed by the Province, and earn a return based on changes in the market value of the assets of the Used Fuel Segregated Fund.

If there is a surplus in the Used Fuel Segregated Fund such that the underlying liabilities, as defined by the most recently approved ONFA reference plan, are at least 110 percent funded after taking into account the committed return adjustment, the Province has the right, at any time, to access the excess amount greater than 110 percent.

Upon termination of the ONFA, the Province has the sole right to any surplus in the fund. Accordingly, when the Used Fuel Segregated Fund is overfunded after taking into account the committed return adjustment, OPG limits the fund earnings it recognizes in the consolidated financial statements by recording an amount due to the Province, such that the balance of the fund is equal to the cost estimate of the funding liability based on the most recently approved ONFA reference plan. In accordance with the ONFA, neither OPG nor the Province have a right to direct any amounts from the Used Fuel Segregated Fund to the Decommissioning Segregated Fund.

Provincial Guarantee

In accordance with the *Nuclear Safety and Control Act* (Canada), the CNSC requires OPG to have sufficient funds available to discharge its existing nuclear waste management and nuclear facilities decommissioning obligations. The CNSC process requires the CNSC financial guarantee requirement to be updated once every five years and for OPG to provide an annual report to the CNSC on the assumptions, fund asset values and resulting financial guarantee requirements. The CNSC financial guarantee requirement calculation takes into account used nuclear fuel and L&ILW expected to be generated to the end of each year.

In 2022, the CNSC accepted OPG's proposed CNSC financial guarantee requirement for the 2023-2027 period to be satisfied by the forecast fair market value of the Nuclear Segregated Funds without the requirement of a Provincial guarantee. As provided by the terms of the ONFA, the Province is committed to provide a Provincial guarantee to the CNSC as required, on behalf of OPG, should there be a shortfall between the CNSC financial guarantee requirement and the fair market value of the Nuclear Segregated Funds during the 2023-2027 period, as it has done in the past. OPG pays the Province an annual guarantee fee equal to 0.5 percent of the outstanding amount, if any, of the Provincial guarantee.

Pension and Other Post-Employment Benefits

The determination of OPG's pension and OPEB costs and obligations is based on accounting policies and assumptions discussed below.

OPG's post-employment benefit programs covering most of the regular employees include a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, other post-retirement benefits (OPRB) including group life insurance and health care benefits, and long-term disability (LTD) benefits. Certain post-employment defined benefit programs are also provided by the Nuclear Waste Management Organization (NWMO) and subsidiaries of the Company, all of which are consolidated into OPG's financial results. Certain subsidiaries of the Company sponsor defined contribution employee savings plans for eligible employees, under which each of employer and employees make contributions according to the plan terms. The OPG defined benefit pension plan is indexed to inflation, subject to certain maximums. Unless otherwise noted, information on the Company's post-employment benefit programs is presented on a consolidated basis.

Accounting Policy

OPG recognizes the funded status of its defined benefit plans on the consolidated balance sheets. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation, on a plan-by-plan basis.

OPG accrues its obligations under defined benefit pension and OPEB plans in accordance with US GAAP. The obligations for defined benefit pension and OPRB are determined using the projected benefit method pro-rated on service. The obligation for LTD benefits is determined using the projected benefit method on a terminal basis. Defined benefit pension and OPEB obligations are impacted by factors including demographic (such as mortality and retirement) and economic (such as discount rates, salary levels, inflation and health care cost escalation) assumptions, experience gains or losses, and adjustments arising from plan amendments. Defined benefit pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions.

Pension fund assets include domestic and international equity securities, corporate and government fixed income securities, pooled funds, real estate, infrastructure and other investments. These assets are managed by professional

investment managers. The pension funds do not invest in equity or debt securities issued by OPG or its subsidiaries and partnerships. Pension fund assets of defined benefit pension plans are valued using market-related values for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value for pension fund assets of the OPG defined benefit pension plan recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

Defined benefit pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, recognition of past service costs or credits resulting from plan amendments, and recognition of actuarial gains or losses resulting from changes in assumptions and experience gains and losses. Past service costs or credits arising from defined benefit pension and OPRB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the corresponding plan. Past service costs or credits arising from amendments to LTD benefits are immediately recognized as OPEB costs in the period incurred. Due to the long-term nature of pension and OPRB liabilities, the excess of the net cumulative unamortized gain or loss over ten percent of the greater of the benefit obligation and the market-related value of the plan assets (the corridor) for each plan is amortized over the expected average remaining service life of the employees covered by the plan, which represents the period during which the associated economic benefits are expected to be realized by the Company. Actuarial gains or losses for LTD benefits are immediately recognized as OPEB costs in the period incurred.

Actuarial gains or losses and past service costs or credits arising during the year that are not recognized immediately as components of defined benefit plan costs are recognized as increases or decreases in other comprehensive income (OCI), net of income taxes. These unamortized amounts in AOCI are subsequently reclassified and recognized as amortization components of pension and OPRB costs as described above.

As at December 31, 2024, the unamortized net actuarial loss (gain) and unamortized past service costs (credits) for the defined benefit pension and OPEB plans totalled a net gain of $23 million (2023 – a net loss of $664 million). Details of the unamortized net actuarial loss (gain) and unamortized past service costs (credits) as at December 31 were as follows:

	Registered Pension Plans		**Supplementary Pension Plans**		**Other Post-Employment Benefits**	
(millions of dollars)	**2024**	**2023**	**2024**	**2023**	**2024**	**2023**
Net actuarial (gain) loss not yet subject to amortization due to use of market-related values	**(340)**	180	**-**	-	**-**	-
Net actuarial loss (gain) not subject to amortization due to use of the corridor	**853**	1,057	**40**	38	**(259)**	(251)
Net actuarial (gain) loss subject to amortization	**(9)**	-	**57**	49	**(428)**	(435)
Unamortized net actuarial loss (gain)	**504**	1,237	**97**	87	**(687)**	(686)
Unamortized past service costs (credits)	**11**	(5)	**-**	-	**52**	31

OPG records an offsetting regulatory asset or regulatory liability for the portion of the pension and OPEB-related adjustments to AOCI that is attributable to the regulated operations in order to reflect the expected recovery or refund of these amounts through future regulated prices charged to customers. For such recoverable or refundable portion, OPG records a corresponding change in this regulatory asset or regulatory liability for the amount of the increases or decreases in OCI and for the reclassification of AOCI amounts into benefit costs during the period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Accounting Assumptions

Assumptions are significant inputs to actuarial models that measure defined benefit pension and OPEB obligations and related effects on operations. Discount rate, inflation rate and changes in salary levels are three key assumptions in the determination of benefit costs and obligations. In addition, the expected long-term rate of return on plan assets is a key assumption in the determination of defined benefit registered pension plan cost and the health care cost trend rate is a key assumption in the determination of OPEB cost and obligations. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality and employee turnover, are evaluated periodically by management in consultation with independent actuaries. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors giving rise to actuarial gains and losses.

The discount rates, which are representative of the AA corporate bond yields, are used to calculate the present value of the expected future cash flows on the measurement date in order to determine the projected benefit obligations for the Company's employee benefit plans. A higher discount rate decreases the benefit obligations and decreases benefit costs. The discount rate used to determine the projected defined benefit pension and OPEB benefit obligations as at December 31, 2024 was approximately 4.7 percent**.** This represents an increase compared to the discount rate of approximately 4.6 percent that was used to determine the obligations as at December 31, 2023.

OPG uses a full yield curve approach to estimate the service and interest cost components of defined benefit pension and OPEB costs, whereby specific spot rates along the yield curve used in the determination of the projected benefit obligations are applied to the relevant projected cash flows.

The expected rate of return on defined benefit pension plan assets is determined based on the pension fund's asset allocation and the expected return considering long-term risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Regulatory Authority of Ontario in September 2024, with an effective date of January 1, 2024. The estimated annual funding requirements taking into account the new actuarial valuation are outlined in the section, *Liquidity and Capital Resources* under the heading, *Contractual Obligations*. As part of the valuation, the plan's demographic and other assumptions were reviewed and revised, as necessary, by independent actuaries. Using updated demographic data as at January 1, 2024 and demographic assumptions consistent with the new funding valuation for the registered pension plan, OPG conducted a comprehensive actuarial valuation for accounting purposes of the OPG defined benefit pension and OPEB plans in 2024. The results of this valuation were reflected in the 2024 year-end obligations reflecting appropriate assumptions for accounting purposes as at December 31, 2024.

The position of the registered pension plan, for accounting purposes, increased from a deficit of $522 million as at December 31, 2023 to a surplus of $337 million as at December 31, 2024. This increase was largely due to the excess of actual return on pension assets values over interest costs on the liabilities during 2024 and a re-measurement of the benefit obligations at the end of 2024 reflecting an increase in the discount rates.

The projected benefit obligations for OPEB plans increased from $2,770 million as at December 31, 2023 to $2,848 million as at December 31, 2024. This increase was largely due to the interest costs on the liabilities during 2024.

A change in the following assumptions, holding all other assumptions constant, would increase (decrease) defined benefit pension and OPEB costs for the year ended December 31, 2024 as follows:

(millions of dollars)	Registered Pension Plans [1]	Supplementary Pension Plans [1]	Other Post-Employment Benefits [1]
Expected long-term rate of return			
0.25% increase	**(40)**	**n/a**	**n/a**
0.25% decrease	**40**	**n/a**	**n/a**
Discount rate			
0.25% increase	**(13)**	**(1)**	**(10)**
0.25% decrease	**14**	**1**	**11**
Inflation [2]			
0.25% increase	**60**	**2**	**1**
0.25% decrease	**(54)**	**(1)**	**(1)**
Salary increases			
0.25% increase	**16**	**4**	**1**
0.25% decrease	**(15)**	**(3)**	**(1)**
Health care cost trend rate			
1% increase	**n/a**	**n/a**	**66**
1% decrease	**n/a**	**n/a**	**(50)**

n/a – change in assumption not applicable.
[1] Excludes the impact of regulatory accounts.
[2] With a corresponding change in the salary increase assumption.

Asset Retirement Obligation

OPG recognizes an ARO related to fixed asset removal and nuclear waste management, discounted for the time value of money. OPG estimates both the amount and timing of future cash expenditures based on the plans for fixed asset removal and nuclear waste management. The ARO is comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear, thermal, and solar generating facilities and other facilities. Costs are expected to be incurred for activities such as preparation for safe storage and safe storage of nuclear generating stations, dismantlement, demolition and disposal of facilities and equipment, remediation and restoration of sites, and the ongoing and long-term management of used nuclear fuel and L&ILW. The liabilities associated with the decommissioning of the nuclear generating stations and the long-term management of used nuclear fuel comprise the most significant amounts of the total obligation.

The nuclear decommissioning liability includes the estimated costs of closing the nuclear generating stations after the end of their service lives, which includes preparation and placement of the stations into a safe storage state followed by an assumed safe storage period prior to station dismantlement and site restoration. Activities associated with the placement of stations into a safe storage state include defueling and de-watering of the nuclear reactors. OPG is responsible for the nuclear waste management and nuclear decommissioning obligations associated with the Bruce nuclear generating stations and includes the associated costs in its ARO. Pursuant to the lease agreement, Bruce Power must return the Bruce nuclear generating stations to OPG together, in a defueled and de-watered state. As such, these defueling and de-watering costs are not part of OPG's ARO.

To estimate the liability for used nuclear fuel management, OPG has adopted an approach consistent with the Adaptive Phased Management (APM) concept approved by the Government of Canada. The NWMO is responsible for the design and implementation of Canada's plan for the long-term management of used nuclear fuel. The APM plan contemplates the long-term permanent disposal of the used nuclear fuel in a deep geological repository (DGR) after a collaborative process of communication and engagement with Canadians aimed at selecting a suitable geological site with an informed and willing host community.

The life cycle costs of L&ILW management include the costs of processing and storage of such materials during and following the operation of the nuclear generating stations, as well as the costs of the ultimate long-term management of these materials. The assumptions used to establish the obligation for these costs recognized in the consolidated financial statements at December 31, 2024 include conceptual long-term disposal strategy assumptions consistent with the NWMO's recommended strategy for the long-term management of irradiated wastes in Canada as set out in its Integrated Strategy for Radioactive Waste (ISRW) prepared at the request of the Government of Canada and subsequently accepted by the federal Minister of Energy and Natural Resources in 2023. The strategy contemplates disposal of low-level waste in near-surface disposal facilities to be implemented by the waste owners and disposal of intermediate-level waste and the small amount of non-fuel high-level waste in a central DGR to be implemented by the NWMO. OPG will continue to evaluate underlying assumptions and estimates based on available information, including developments related to the NWMO's future siting process for such DGR.

The following costs are recognized as a liability on OPG's consolidated balance sheets:

- the present value of the costs of decommissioning the nuclear, thermal and solar generating facilities and other facilities after the end of their useful lives;
- the present value of the fixed cost portion of nuclear waste management programs that are required based on the total volume of used nuclear fuel and L&ILW expected to be generated over the assumed lives of the nuclear generating stations; and
- the present value of the variable cost portion of nuclear waste management programs taking into account volumes of such materials generated to date.

A number of significant assumptions used in the calculation of the accrued liabilities are subject to inherent uncertainty and judgement. The significant assumptions underlying operational and technical factors used in the calculation of the accrued liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the programs, construction of assumed disposal facilities, station end-of-life dates, disposal methods, financial indicators, decommissioning strategy and the technology employed, may result in significant changes to the value of the accrued liabilities. With programs of such long-term duration and the evolving technology to handle nuclear waste, there is a significant degree of inherent uncertainty surrounding the measurement of the costs for these programs, including from factors beyond the Company's control. These costs may increase or decrease materially over time.

The estimates for the Nuclear Liabilities are reviewed on an ongoing basis as part of the overall nuclear waste management program. A comprehensive reassessment of all underlying assumptions and baseline cost estimates is performed periodically, at least once every five years, in line with the required ONFA reference plan update process. Changes in the Nuclear Liabilities resulting from changes in assumptions or estimates that impact the amount or timing of the estimated undiscounted future cash flows are recorded as an adjustment to the liabilities. Upward revisions in the Nuclear Liabilities represent the present value of a net increase in future undiscounted cash flows determined using a current credit-adjusted risk-free rate. Downward revisions in the Nuclear Liabilities represent the present value of a net decrease in future undiscounted cash flows determined using the weighted average discount rate reflected in the existing liability. Resulting changes in the related asset retirement costs are capitalized as part of the carrying amount of nuclear fixed assets in-service.

The most recent comprehensive update of the baseline cost estimates for the Nuclear Liabilities was completed in December 2021 and is contained in the 2022 ONFA Reference Plan. Effective December 31, 2023, OPG revised the accounting end-of-life assumptions for Units 5 to 8 of the Pickering GS from 2024 to 2070, reflecting the results of the updated refurbishment feasibility assessment approved by the Board in August 2023 and the Province's January 2024 announcement supporting OPG to proceed with next steps toward refurbishing these units. A resulting increase of $160 million was recorded to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the assets as at December 31, 2023. These changes did not have a material impact on net income in 2024, with the associated impact on expenses largely offset by OEB-authorized regulatory accounts.

For the purposes of calculating OPG's Nuclear Liabilities, as at December 31, 2024, consistent with the current accounting end-of-life assumptions, nuclear facilities decommissioning activities are projected to occur over approximately the next 80 years.

The liability for nuclear fixed asset removal and nuclear waste management on a present value basis as at December 31, 2024 is $25,773 million (2023 – $25,116 million). As at December 31, 2024, the undiscounted estimated future cash flows associated with OPG's Nuclear Liabilities in 2024 dollars are as follows:

(millions of dollars)	**2025**	**2026**	**2027**	**2028**	**2029**	**Thereafter**	**Total**
Expenditures for nuclear fixed asset removal and nuclear waste management [1]	814	849	597	499	374	47,050	50,183

[1] The majority of the expenditures are expected to be reimbursed by the Nuclear Segregated Funds established by the ONFA. Any contributions required under the ONFA are not included in these undiscounted cash flows.

The liability for non-nuclear fixed asset removal was $269 million as at December 31, 2024 (2023 – $270 million). This liability primarily represents the present value of estimated costs of decommissioning OPG's thermal generating stations at the end of their service lives. For the purpose of measuring the non-nuclear fixed asset removal liability, thermal asset removal activities are assumed to take place over approximately the next 40 years. The amount of undiscounted estimated future cash flows associated with the thermal fixed asset removal liabilities is approximately $351 million.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arm's-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model.

The fair value of financial assets and liabilities for which quoted prices in an active market are available, including exchange traded derivatives and other financial instruments, are determined directly from those quoted market prices.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing as at the consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives and fund investments. Various other fund investments are valued at the unit values supplied by the fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that may affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If the valuation technique or model is not based on observable market data, specific valuation techniques are used, primarily based on recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions and other relevant factors.

OPG's use of financial instruments exposes the Company to certain risks, including credit risk, foreign currency risk and interest rate risk. A discussion of how OPG manages these and other risks is found in the section, *Risk Management*.

RISK MANAGEMENT

Overview

OPG faces various risks that could significantly impact the achievement of its business imperatives. The objective of risk management is to identify, assess and mitigate key risks and to preserve and increase the value of the Shareholder's investment in the Company.

The Audit and Risk Committee of the Board is mandated to fulfill the Board's oversight responsibilities for matters relating to the identification and management of the Company's key business risks. OPG's ERM Framework is designed to identify and evaluate risks on the basis of their potential impact on the Company's business imperatives and business plan objectives. Formal risk management policies, procedures and systems are in place to identify, assess and mitigate risks to the Company. Senior management also establishes set limits for market risk, credit risk and energy trading activities of the Company.

The key risks to OPG's business imperatives are briefly described below. These are key risks that management believes could materially affect the Company's business, revenues, net income, cash flow, assets or capital resources. There may be further risks and uncertainties that are not presently known, or that are not currently believed to be material, that may in the future adversely affect the Company's performance or financial condition.

Risks to Achieving Operational Excellence

OPG is exposed to a range of operational risks associated with its existing assets that could adversely impact generation output, safety performance and operating results. As described below, the operational risks of a generating station include aspects such as cyber security, supply chain, occupational safety, equipment reliability, human resources, climate change, regulatory requirements and emergency management.

Cyber Security

Cyber security incidents may compromise the availability, integrity, or confidentiality of OPG's information systems, with potential impacts on energy production, public and employee safety, and the Company's reputation. Global cyber threats are rising, with geopolitical tensions and Artificial Intelligence use by threat actors for malicious purposes intensifying risks. OPG's cyber security program includes policies and strategies to detect, respond to, and recover from incidents. OPG continuously assesses its cyber security risk profile and enhances protection measures, workforce training, and third-party management to address evolving threats.

OPG's operations in Ontario must comply with reliability standards that apply to the Bulk Electric System elements specified under North American Electric Reliability Corporation and the relevant Bulk Power System facilities as determined by the Northeast Power Coordinating Council. A subset of these standards establishes the reliability requirements that relate to cyber security. OPG's operations in the US must comply with applicable cyber security requirements as set out by the FERC. In addition, OPG's nuclear cyber assets are subject to CNSC licensing conditions and regulatory requirements. For other cyber assets not subject to applicable regulatory requirements, OPG has adopted a risk-based approach based on the National Institute of Standards and Technology Cyber Security Framework to manage its cyber security.

The Company has policies and programs in place to manage cyber risks; these programs are subject to oversight by management and the Board. OPG's current cyber programs primarily focus on the following:

- Protecting the Company's assets from cyber attacks and safeguarding sensitive information;
- Improving cyber security protection, detection, incident response and recovery capabilities to minimize the impact of adverse cyber events;
- Adopting industry leading practices to reduce third-party cyber security risks by introducing cyber security requirements into commercial agreements and enhancing related governance;

- Ongoing cyber security awareness and training of the workforce; and
- Embedding security by design across the Company to proactively assess and manage cyber risk.

Supply Chain

OPG's ability to operate effectively is in part dependent upon timely access to equipment, materials and service suppliers. Loss of key suppliers, particularly for the nuclear business given the limited number of qualified vendors, and vendor performance risks could affect OPG's operations and execution of major capital projects. This includes OPG's new development and refurbishment projects which require commitment from experienced vendors who may be limited in their capacity to successfully service OPG and other key customers in parallel, given an increased focus on energy transition and energy security in Canada and globally. These constraints could affect OPG's growth initiatives.

OPG mitigates these risks, to the extent possible, through:

- Contract negotiations to achieve mutually agreeable procurement terms;
- Programmatic partnerships with original equipment manufacturers;
- Supplier monitoring, including supplier scorecards and relationship management;
- Advanced procurement of critical long-lead components; and
- Diversification of supplier base and business continuity plans.

Through OPG's supply chain capacity program, increased activities are underway to identify critical goods and services risks by assessing supply and demand conditions and to develop mitigation strategies for the top risk areas. OPG also seeks to ensure that vendors have appropriate strategies, such as effective succession planning, to successfully execute on their contracted deliverables over the life of the projects.

OPG also faces industry-wide risks related to inflation, material availability and geopolitical tensions including trade disputes that could potentially lead to supply chain disruptions or cost increases. The risk related to trade disputes is discussed under the heading, *Tariffs and Other Trade Restrictions*.

Tariffs and Other Trade Restrictions

The potential imposition of tariffs and other trade restrictions may result in supply chain disruptions and increased costs of procurement. The trade disputes could also impact demand for Ontario's electricity, both due to reduced economic output as well as the potential for energy trade restrictions between Canada and the United States. A prolonged trade dispute between Canada and the United States has the potential to structurally alter the Canadian economy, depreciate the Canadian dollar in the near term, and impact inflation and costs of financing. This may adversely impact OPG's operations, projects, growth initiatives and financial condition.

OPG is monitoring and managing the above risks by working with the supplier partners, negotiating appropriate contractual terms for new purchases, reviewing procurement strategies, and evaluating and managing procurement exposures from foreign countries. OPG is also proactively engaging with the Canadian federal and provincial governments and industry groups to identify and determine the impact on critical materials and equipment needed to maintain and build electricity infrastructure.

Labour Relations

As at December 31, 2024, approximately 83 percent of OPG and its subsidiaries' regular workforce was represented by a union. As such, there is an inherent risk of labour relations disputes in the Company's operations. There is also a risk that a renewal collective agreement in the future may include terms that will unfavourably impact OPG's costs and ability to efficiently manage operations. OPG has contingency plans in place in the event of a labour disruption.

For further details on the collective bargaining agreements, refer to the section, *Significant Developments* under the heading, *Operational Excellence – Power Workers' Union Collective Agreement* and the section, *Liquidity and Capital Resources* under the heading, *Contractual Obligations – Collective Agreements*.

Health and Safety	OPG's operations involve inherent occupational safety risks and hazards that could impact the achievement of the Company's health and safety goals. OPG is committed to continuous improvement through its safety management systems and by continuing to foster a strong health and safety culture among its employees and contractors. The safety management systems serve to focus the Company on proactively managing safety risks and hazard exposures to employees and contractors. OPG also strategically engages with external parties to conduct benchmarking and audits. These activities are designed to ensure that the safety management systems achieve the intended results and maximize the opportunity to incorporate program improvements.
Generating Asset End of Life	Major damage or deterioration of station components and systems may result in generating assets reaching end of life prematurely. An earlier than planned retirement of a generating unit or station would result in a reduction of OPG's future generation revenue and cash flow, asset impairment or write-down and reductions in the workforce. Key life-limiting components at OPG's nuclear generating stations include fuel channels, feeder tubes, steam generators and other reactor components. Risks inherent in maintaining commercial operations to a generating station or unit's planned end of life include: • Discovery of unexpected conditions; • Equipment failures; • Rate of degradation of critical plant components; and • A requirement for significant plant modifications. To mitigate these risks, for the nuclear operations, OPG implements actions recommended by technical assessments into each generating station's outage work program. OPG also incorporates these actions into a comprehensive inspection and maintenance program as part of the stations' life cycle management plans. The risks include fuel channel degradation resulting in Units 5 to 8 of the Pickering GS ending pre-refurbishment operations prior to September 2026. This risk is being addressed through fuel channel life extension activities, which include surveillance, inspections and technical analysis to confirm fitness-for-service of fuel channels components. For non-nuclear operations, OPG maintains a rigorous maintenance and asset management program to ensure continuing operations of hydroelectric, thermal and solar assets.
Asset Condition and Generation Variability	The uncertainty associated with electricity production by OPG's generating units is primarily driven by the condition of station components and systems, which are subject to the effects of aging. Deterioration in station components or systems may be significantly greater than anticipated or may occur in an unexpected manner. The primary implications of these risks may include additional safety requirements, lower than expected electricity generation and revenues, and higher than expected operating or capital costs. To respond to these risks, OPG continues to: • Make enhancements to the asset management program; • Monitor performance and implement inspection and maintenance programs; • Identify future work required to sustain and, as appropriate, upgrade station equipment; and • Undertake projects required to reliably operate within design and operating parameters. Following inspections, it was determined that the primary moisture separators need to be replaced on all Darlington GS units. Operating units with degraded moisture separators could impact downstream components and result in an unplanned outage or extension of a planned outage. OPG is utilizing a comprehensive lessons learned program and robust risk management practices as it continues to replace the primary moisture separators on the Darlington GS units. There is also a strategy in place to address secondary moisture separator degradation through planned inspections and limited secondary moisture separator repair. Further information on the project can be found in the section, *Core Business and Outlook under* the heading, *Operational Excellence – Electricity Generation Production and Reliability – Darlington GS*.

Human Capital	The development of new leaders and attraction and retention of qualified employees in critical roles are key factors to OPG's success. The risk associated with the availability of skilled and experienced resources continues to exist for OPG in specific areas, including engineering, operations, leadership and project management positions. To mitigate this risk, OPG utilizes workforce planning and resourcing strategies to ensure that the Company has a diverse workforce with the right skill sets for the safe and effective operations of generating facilities and successful delivery of major projects and growth and transformation strategies. Risk mitigation includes succession planning, talent attraction and retention strategies, and knowledge management programs to ensure ongoing workforce capability. OPG expects to continue to meet the human resource needs of the business by developing existing employees and hiring in specific areas while addressing the workforce implications associated with the end of commercial operation of Unit 1 and Unit 4 of the Pickering GS and transition to the planned refurbishment of Units 5 to 8 of the Pickering GS. Legislative compensation constraints continue to pose challenges to OPG's ability to attract and retain necessary talent. This includes the *Compensation Framework Regulation 406/18* under the *Broader Public Sector Executive Compensation Act, 2014*, which imposes a cap on base salary, on a role by role basis, for designated executives in Ontario's broader public sector.
Nuclear Waste	There are currently no licensed facilities in Canada for the permanent disposal of used nuclear fuel, low-level waste or intermediate-level waste. The lack of a permanent disposal site means that these materials are stored in temporary locations. The interim storage of used nuclear fuel and L&ILW at OPG is subject to rigorous oversight and monitoring. OPG's assumptions related to the long-term management of used nuclear fuel and L&ILW are informed by Canada's *Policy for Radioactive Waste and Decommissioning.* For used nuclear fuel, the NWMO has developed a process for moving forward with the APM plan as the long-term solution for Canada's used nuclear fuel. The APM plan contemplates the long-term permanent disposal of used nuclear fuel in a DGR. On November 28, 2024, the NWMO announced that it had selected Wabigoon Lake Ojibway Nation and the Township of Ignace, Ontario as the host communities for the future site of Canada's DGR for used nuclear fuel. The NWMO is now advancing the project into the regulatory decision-making process, with DGR operations planned to begin between 2040 and 2045. In October 2023, the Government of Canada accepted the NWMO's ISRW submission, including the recommendation that intermediate-level waste and the small amount of non-fuel high-level waste be disposed in a central DGR to be implemented by the NWMO. In January 2024, the CNSC granted Canadian Nuclear Laboratories a licence to construct Canada's first near-surface disposal facility, at the Chalk River site in Deep River, Ontario, for the purpose of permanently disposing of solid low-level irradiated waste. OPG continues to monitor developments related to the implementation of the APM plan and the ISRW and to explore solutions for the safe long-term management of its low-level waste. The Company also continues to advance initiatives to safely reduce the environmental footprint of L&ILW requiring long-term disposal by maximizing opportunities for processing, volume reduction, and recycling of clean materials.
Climate Change and Extreme Weather Events	In recent years, Ontario and other regions in North America where OPG operates have experienced an increase in climate and extreme weather events such as severe flooding during spring freshets and low water levels in late summer. Such events may impact OPG's operations and condition of the generating fleet. To mitigate the physical risks posed by extreme weather, OPG monitors developments in climate science and adaptation practices, and works with stakeholders to define adaptation requirements through analysis and by understanding the potential impacts on watersheds, assets, operations and the electricity market. OPG collaborates with all levels of government in Canada, local communities and industry on climate change adaptation initiatives,

with the goal of increasing the resilience of the electricity sector and other critical infrastructure. Resilience programs to protect OPG's assets against severe weather events remain in place and are incorporated into the Company's Climate Change Plan.

The risks and opportunities related to climate change legislation are discussed under the heading, *Risks to Maintaining Financial Strength – Government Legislation and Regulation Changes*. For further details on OPG's response to the effects of climate change, refer to the section, *Environmental, Social, Governance and Sustainability.*

Environment

OPG's operations and facilities are subject to environmental compliance obligations in the jurisdictions in which they operate. These obligations include protection of land, water, air, living organisms and natural systems. Failure to comply with applicable environmental laws and regulations, including violation of regulatory limits on emissions, may result in enforcement actions, remediation actions or restrictions to operations. Changes in compliance obligations can result in new requirements and increased costs. OPG has an EMS to manage its environmental responsibilities. For further details, refer to the section, *Environmental, Social, Governance and Sustainability*.

Hydroelectric Generation

OPG's hydroelectric generation is exposed to risks associated with water flows and Ontario SBG conditions.

The extent to which OPG can operate its hydroelectric generating facilities depends upon the availability of water. Significant variability in weather, including impacts of climate change and the extreme weather associated with it, could affect water flows. Longer term changes in precipitation patterns and amounts, water temperatures and ambient air temperatures can impact the availability of water resources and resulting electricity production at OPG's hydroelectric generating stations. For OPG's regulated hydroelectric generation, the financial impact of variability in electricity production due to differences between the forecast water conditions underpinning the hydroelectric base regulated prices and the actual water conditions is captured in an OEB-approved regulatory account.

Surplus baseload generation continues to be present in Ontario when electricity supply exceeds demand, including exports out of the province. To manage SBG conditions, the IESO may require OPG to reduce hydroelectric generation. A regulatory account authorized by the OEB helps to mitigate the financial impact of electricity production forgone due to SBG conditions at OPG's regulated hydroelectric generating stations in Ontario.

Regulatory Compliance

OPG is subject to extensive legislation and regulations by various entities in the jurisdictions in which it operates, including the CNSC, the OEB, the IESO and the FERC.

The uncertainty associated with nuclear regulatory compliance is driven by plant aging, changes to technical codes, and challenges raised by members of the public at regulatory hearings, particularly in the areas of safety, environment and emergency preparedness. Addressing these requirements could add incremental cost to operations, including replacement or modification of station components or additional requirements for management of nuclear waste. In some instances, there may be additional requirements resulting from changes in the interpretation of technical regulations or from emergent conditions that may result in increased effort on the part of the Company.

The operation of most of OPG's hydroelectric facilities in the US is authorized by the FERC, which includes the issuance of licences for larger facilities with terms ranging 30 to 50 years. A number of OPG facilities are in various stages of the relicensing process. There is a risk that in issuing a new licence, the FERC will impose new conditions that either restrict operations or require incremental expenditures related to the environment, recreation or other infrastructure at the facilities.

The risks related to other regulatory bodies are discussed under the headings, *Risks to Maintaining Financial Strength – Rate Regulation*, *Risks to Maintaining Financial Strength – Electricity Markets* and *Risks to Maintaining Financial Strength – Government Legislation and Regulation Changes.*

Business Continuity and Emergency Management	OPG may be exposed to natural, technological or human-caused hazards including significant events against which it is not fully insured or indemnified. These hazards have the potential to disrupt operations resulting in decreased electricity generation revenue or additional costs to repair damages and restore operations. OPG's business continuity program provides a framework to build resilience into critical business processes to ensure continued operation of critical business functions. OPG's emergency management program is designed to ensure that the Company can resolve an emergency in a timely and effective manner. OPG's plans and implementation procedures identify immediate response actions to be taken to protect the health and safety of workers and the public, and to limit the impact of an incident on site security, production capability and the environment. The program elements are designed to meet or exceed legal and regulatory requirements. OPG regularly monitors and assesses global events, such as emerging geopolitical events, natural disasters and pandemics, and prepares contingency plans should they have the potential to impact OPG's operations, workers, customers or stakeholders.

Risks to Achieving Project Excellence

As a capital-intensive business, OPG undertakes a large portfolio of projects with significant investments. There may be an adverse effect on the Company if it is unable to obtain necessary approvals for the projects, effectively manage the projects on time and on budget, or fully recover project costs and earn an appropriate return on project investments. Projects may also impact OPG's borrowing capacity and credit rating. OPG mitigates risks associated with project execution through a scalable project management methodology applicable to projects across the Company. Risks associated with certain current major projects are described below. Additionally, there are risks associated with the loss of key suppliers, as further discussed under the heading, *Risks to Achieving Operational Excellence – Supply Chain.*

Key Trades Availability	Competing capital and infrastructure projects within Ontario, and throughout Canada, may limit the availability of key tradespeople to work on OPG's current and future projects, including the Darlington Refurbishment project, refurbishment and expansion of hydroelectric generating stations, the DNNP and the planned refurbishment of Units 5 to 8 of the Pickering GS. There is a risk that skilled tradespeople may choose to work on non-OPG projects, thereby impacting the Company's ability to complete projects on schedule and budget and with requisite quality. OPG has a dedicated team that is mitigating this risk through: active monitoring of the supply and demand of key tradespeople; collaborating with competing organizations, such as Bruce Power, to build capacity within the current supply by coordinating timing of project schedules, where appropriate; building new sources of supply through partnerships with other organizations, trade unions, and educational institutions; and implementing strategies for resource retention.
Darlington Refurbishment	There are potential financial and reputational risk exposures for OPG if actual costs for the Darlington Refurbishment project exceed the budget or if OPG does not meet the project schedule, with recovery of any project costs exceeding $12.8 billion subject to a future review by the OEB. In addition, failure to achieve the objectives of the project may potentially impact the post-refurbishment performance or useful life of the generating units. With three of the four units successfully returned to service to date, OPG is continuing to utilize a comprehensive lessons learned program to benefit project performance on the final unit being refurbished. OPG is also continuing to use robust risk management practices to manage a number of risks related to the Darlington Refurbishment project, including availability of skilled craft resources and vendor performance.
Small Modular Reactors	OPG is advancing the deployment of SMRs to help meet future electricity needs, with the DNNP progressing toward construction of Canada's first commercial grid-scale SMR. The selected SMR design for the DNNP, GE Hitachi Nuclear Energy's (GE-Hitachi) BWRX-300, is the tenth evolution of the boiling water reactor, which partially mitigates risks associated with this first-of-a-kind technology. Nevertheless, there are inherent risks to OPG's plans to deploy SMRs at the DNNP site. Risks associated with the SMR deployment include: uncertainties associated with obtaining regulatory approvals for new nuclear technology; project cost and schedule risks; potential for opposition from Indigenous communities; and public acceptance of additional nuclear waste. Risk mitigation strategies include robust project planning and project oversight; completion of engineering design with OPG's oversight; implementation of an integrated project delivery model with partners; and meaningful engagement with Indigenous communities and stakeholders. Ontario Regulation 53/05 prescribes any SMR at the DNNP site as a regulated facility by the OEB and provides for recovery of associated planning, preparation and construction costs, subject to a review by the OEB. OPG applies appropriate technical and commercial risk oversight to evaluate potential opportunities for commercial deployment of SMRs, including identification of any regulatory, market and credit risks that may arise.

Pickering Refurbishment

In January 2024, the Province announced its support for OPG to proceed with next steps toward refurbishing Units 5 to 8 of the Pickering GS after their planned shutdown in 2026. In January 2025, the Province further announced its approval for OPG's plan to proceed with the project definition phase. This complex megaproject presents inherent cost, schedule and regulatory risks, which will continue to be managed consistent with OPG's enterprise project management approach. As part of the definition phase, OPG will complete a high-quality cost estimate and schedule for the project, progress detailed engineering, further procurement and contracting work, continue to optimize project scope, and develop the project execution plan. OPG will also leverage lessons learned from the Darlington Refurbishment project to inform risks and project management activities as the project advances.

Further details can be found in the section, *Significant Developments* under the heading, *Project Excellence – Pickering Refurbishment.*

Risks to Maintaining Financial Strength

Risks related to macro-economic factors, rate regulation, commodity markets, financial markets and long-term obligations could significantly impact OPG's financial performance. The Company is also exposed to risks due to changes in the electricity markets and renewal of energy supply contracts. Geopolitical tensions and conflicts could increase a number of these risks by driving long-lasting implications for commodity, financial and electricity markets, as well as government policy. As a result of changes in economic factors or the electricity market, OPG may make decisions to invest, divest, or discontinue investments to maintain or enhance long-term financial strength.

Government Legislation and Regulation Changes

OPG's core business and strategy may be impacted by changes to legislation and regulations in the jurisdictions in which the Company operates. Matters that are subject to regulation include, among others, rate regulation, electricity generating operations, nuclear waste management and nuclear decommissioning, the electricity market, the environment, trade and taxation, including investment tax credit programs. Regulatory bodies may change or enact regulations or rules that could increase OPG's costs, decrease OPG's revenue or limit the Company's ability to recover appropriate costs and earn an appropriate return on its asset investments.

To mitigate legislative risks, where possible, OPG monitors and actively engages with all levels of government in order to determine if future legislation will impact the Company.

In 2019, legislation to amend the *Fisheries Act* to further protect fish and fish habitat came into force in Canada. There is a risk that strengthened fish and fish habitat protection provisions under the *Fisheries Act* may affect OPG's hydroelectric operations. To mitigate this risk, OPG and its industry partners are working with Fisheries and Oceans Canada to help develop the codes, policies and procedures that will determine how the regime is administered. OPG is also developing a compliance strategy.

Canada's plan is to reach net-zero carbon emissions by 2050. In 2021, the Government of Canada passed legislation that commits Canada to achieving this goal. This legislation also establishes requirements for the government to set interim national emissions-reduction targets and credible, science-based plans to achieve these targets. In December 2024, the Government of Canada released the CER, which may limit operations of OPG's thermal generating stations beyond 2035.

OPG's Climate Change Plan goals for OPG to be a net-zero company and a catalyst for net-zero economies are in line with Canada's goal of net-zero carbon emissions by 2050. The Company continues to engage in the development of federal plans and legislation related to energy transition and intends to adapt OPG's Climate Change Plan to changing government policies as appropriate.

Further details on the CER, OPG's GHG compliance obligations and response to climate change can be found in the section, *Environmental, Social, Governance and Sustainability* under the headings, *Environmental* and *Climate Change.*

As discussed in the section, *Core Business and Outlook* under the heading, *Financial Strength – Federal Clean Energy Investment Tax Credits*, OPG is monitoring developments from the

Government of Canada related to the status of the proposed CEITC, for which draft legislation was terminated upon prorogation of the parliament in January 2025. Should these tax credits or similar mechanisms ultimately not be available to OPG, the Company will need to increase the amount of funding from other sources in order to finance certain planned investments in clean energy projects.

Rate Regulation

There is a risk that base regulated prices established by the OEB may not provide for full recovery of actual costs incurred by OPG's regulated operations or allow the regulated operations to earn an appropriate return on the assets, adversely affecting the Company's earnings and cash flow provided by operating activities. This could occur if:

- In setting regulated prices, the OEB makes adjustments to forecasts submitted by OPG or disallows recovery of incurred capital costs;
- OPG is unable to achieve cost reductions in line with OEB-approved stretch factors included in regulated prices under incentive ratemaking; or
- Actual production or costs significantly differ from the forecasts approved by the OEB, due to such factors as unplanned outages or project execution risks.

There is also uncertainty associated with the outcomes of requests for the recovery or refund of regulatory account balances, with a number of such accounts being subject to an OEB prudence review, and outcomes of other regulatory proceedings.

In providing evidence in support of its applications for regulated prices, including disposition of regulatory account balances, OPG aims to clearly demonstrate to the OEB that the costs for the regulated operations are reasonable, prudently incurred and should be fully recovered from customers.

Nuclear Liabilities and Nuclear Segregated Funds

The cost estimates for OPG's nuclear waste management and nuclear decommissioning obligations are based on multiple underlying assumptions and estimates that may change significantly over time. To address this inherent uncertainty, OPG performs a comprehensive review of the underlying assumptions and baseline cost estimates at least once every five years, in line with the required reference plan update process under the ONFA.

The Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA. Investments in the Nuclear Segregated Funds are allocated to domestic and international equity securities, corporate and government fixed income securities, pooled funds, real estate, infrastructure, and other investments. The rates of return earned on the funds in a given period may vary depending on financial market conditions. The asset mix of the funds is determined jointly by OPG and the Province in accordance with the ONFA.

OPG bears the market risk for investment performance related to the portion of the Nuclear Segregated Funds set aside for:

- Decommissioning of the nuclear generating stations; and
- Long-term management of used nuclear fuel in excess of the first 2.23 million bundles and long-term management of L&ILW.

In accordance with the OEB-approved cost recovery methodologies, the performance of the portion of the Nuclear Segregated Funds attributed to the Bruce nuclear generating stations is subject to the Bruce Lease Net Revenues Variance Account. Subject to the funded status of the funds, under the OEB-approved cost recovery methodologies, OPG's net income is exposed to the rate of return risk related to the portion of the Nuclear Segregated Funds attributed to the Darlington and Pickering nuclear generating stations. The income statement impact of the rate of return risk is partly mitigated when the funds are in a fully funded or overfunded position, as a reduction in the Nuclear Segregated Funds due to market conditions would first reduce the surplus in the respective fund before impacting OPG's net income. As at December 31, 2024, both the Decommissioning Segregated Fund and the Used Fuel Segregated Funds were in an overfunded position based on

	the most recently approved ONFA reference plan. For further details, refer to the section, *Core Business and Outlook* under the heading, *Outlook*.
Post-Employment Benefit Obligations	OPG's post-employment benefit obligations and costs and defined benefit registered pension plan contributions could be materially affected in the future by numerous factors including: changes in discount rates, inflation rates and other actuarial assumptions; future investment returns on pension plan assets; experience gains and losses; the funded status of the pension plans; changes in benefits; changes in the regulatory environment including potential changes to the *Pension Benefits Act* (Ontario); changes in OPG's operations; and the measurement uncertainty incorporated into the actuarial valuation process. Contributions to the OPG registered pension plan are determined based on actuarial valuations, which are filed with the appropriate regulatory authorities at least every three years. OPG is required to file actuarial valuations on an annual basis if the solvency funded status of the plan declines below the threshold specified in the regulations of the *Pension Benefits Act* (Ontario). Future actuarial valuations could increase OPG's funding requirements due to market and economic-related conditions. OPG's OPEB obligations are not funded and the associated employee benefits are paid from cash flow provided by operating activities or other sources of liquidity.
Ownership by the Province	The Province owns all of OPG's issued and outstanding common shares and Class A shares. Accordingly, the Province, as represented by the Ontario Ministry of Energy and Electrification, has the authority to make appointments to OPG's Board. OPG could be subject to Shareholder direction under section 108 of the *Business Corporations Act* (Ontario) that can directly influence major decisions. These directions could relate to project development, applications for regulated prices, asset acquisitions, divestitures or other transactions, financing and capital structure, and other matters. As a result, OPG could be required to undertake activities that result in increased expenditures, or that reduce revenue or cash flow relative to the business activities or strategies that would have otherwise been undertaken. In addition, the obligation of OPG's Shareholder to respond to a broad range of matters in its role as the Government of Ontario may create opportunities or risks for OPG which would be pursued or, to the extent possible, would be mitigated to achieve OPG's strategic and business plan objectives. This includes, but is not limited to, actions that may be taken by the Province to support future electricity planning decisions, to mitigate the impact of electricity prices on Ontario consumers, or to respond to trade disputes and other geopolitical tensions.
Credit	The Company's credit risk exposure is a function of its electricity sales, trading and hedging activities, and treasury activities including investing and commercial transactions with various suppliers of goods and services. OPG's credit risk exposure relating to electricity sales is considered low as the majority of sales are through the IESO-administered market in Ontario. The IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market.

The following table summarizes OPG's credit exposure to all counterparties from electricity transactions and trading as at December 31, 2024:

	All Counterparties		Largest Counterparties	
Credit Rating [1]	Number of Counterparties [2]	Potential Exposure [3] *(millions of dollars)*	Number of Counterparties	Potential Exposure *(millions of dollars)*
Investment grade	**49**	**84**	**5**	**70**
IESO [4]	**6**	**607**	**1**	**507**
Other	**29**	**3**	**2**	**1**
Total	**84**	**694**	**8**	**578**

[1] Credit ratings are based on OPG's own analysis, taking into consideration external rating agency analysis where available, as well as recognizing explicit credit support provided through parental guarantees, Letters of Credit or other forms of security. Other category represents counterparties for which the credit rating has not been analyzed by OPG.
[2] OPG's counterparties are defined on the basis of individual master agreements.
[3] Potential exposure is OPG's statistical assessment of maximum exposure over the life of each transaction at a 95 percent confidence interval.
[4] Credit exposure represents an estimated short-term receivable amount arising from OPG's electricity sales into the IESO market. The credit exposure and associated receivable vary each month based on electricity sales. The monthly receivable from the IESO is typically paid to OPG in the subsequent month as per the IESO payment schedule.

Other major components of OPG's credit risk exposure include those associated with vendors that are contracted to provide services or products. OPG manages its exposure to various suppliers or counterparties by evaluating their financial condition and ensuring that the Company holds appropriate collateral or other forms of security.

Commodity Markets

Changes in the market prices of fuels used to produce electricity can adversely impact OPG's earnings and cash flow provided by operating activities.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of electricity generation and supply mix and, as such, are subject to change as these forecasts are updated.

	2025	2026	2027
Estimated fuel requirements hedged *(%)* [1]	78	77	88

[1] Represents the approximate portion of megawatt-hour (MWh) of expected electricity generation (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the price of fuel is fixed, or for which the Company has entered into contractual arrangements to secure the price of fuel or secure the recovery of fuel costs. In the case of regulated and contracted hydroelectric electricity generation in Ontario, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as certain materials, services and fuels purchased for generating stations and major projects, as well as debt issuances, may be denominated in or tied to US dollars. To manage this risk, OPG may periodically employ various financial instruments such as forwards and other derivative contracts, in accordance with approved risk management policies. As at December 31, 2024, OPG had nil in foreign exchange contracts outstanding. Additionally, volatility in the Canadian/US foreign exchange rate impacts OPG's financial results from certain of its subsidiaries, whose operations are based exclusively in the United States.

Interest Rates

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in related interest rates. Interest rate risk for OPG arises with the need to refinance existing debt or undertake new financing. The management of these risks includes using derivatives to hedge the

	exposure in accordance with approved risk management policies. OPG may use interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.
Liquidity	The Company's ability to arrange sufficient and cost-effective debt financing as part of its funding requirements could be adversely affected by a number of factors, including financial market and general economic conditions, the regulatory environment, the Company's results from operations, financial condition and the ratings assigned to the Company by credit rating agencies. In mitigating these risks, OPG utilizes multiple funding sources and forecasts availability of funds, actively monitors funding requirements and strives to maintain its investment grade credit ratings. A discussion of corporate liquidity is included in the section, *Liquidity and Capital Resources*.
Electricity Markets	OPG's revenue can be impacted by external factors related to electricity markets including: the entrance of new participants into the markets; the competitive actions of market participants; electricity demand including exports out of Ontario; changes in the regulatory environment; and variability in wholesale electricity prices in applicable markets. A number of OPG's hydroelectric facilities in the US sell energy and capacity into wholesale electricity markets and therefore are subject to volatility of wholesale electricity market pricing. Revenue from these facilities represents a small portion of OPG's overall revenue. From time to time, the Company may enter into hedging arrangements to further mitigate this risk. OPG continues to monitor the effects of electricity market prices on its US operations. In October 2024, the IESO approved market rules and design required to operationalize the Market Renewal Program, an IESO initiative to redesign the Ontario's electricity markets. According to the IESO, the renewed electricity markets will be launched on May 1, 2025. OPG is actively participating in the Market Renewal Program and continues to collaborate with the IESO. Additionally, OPG is consolidating and upgrading its internal systems and processes to be able to effectively participate in the new market. This requires concurrent changes to certain common business processes and information technology systems, which is being addressed through change management initiatives. This work is progressing as planned. The 2024 Settlement Agreement provides for regulatory mechanisms to address the anticipated impacts from the IESO's Market Renewal Program on OPG's regulated facilities until the effective date of base regulated prices arising from OPG's next application with the OEB. The Market Renewal Program is not expected to have a material impact on OPG's net income.
Contracted Generation	The Company's generating stations in Ontario that operate under ESAs with the IESO are subject to several obligations, including but not limited to availability targets and must-offer obligations committing units to the market during specific hours, as specified in the respective contracts. OPG could incur penalties up to and including termination of the respective contract if these facilities fail to meet their contractual obligations. This risk is mitigated through implementation of maintenance, capital investment and other programs, and internal processes to communicate, monitor and address contractual obligations and milestones. While OPG expects that the generating stations operating under ESAs or other contracts will continue to provide energy and capacity to the respective markets over the term of such agreements, there is a risk that the contracts may not be renewed upon their expiry or that replacement contracts may not be available on acceptable terms.
Litigation	OPG and its subsidiaries are involved in various legal proceedings covering a range of matters arising out of their business activities. Each of these matters is subject to various uncertainties and some of these matters may be resolved unfavourably. It is the Company's belief that the resolution of these matters is not likely to have a material adverse impact on its consolidated financial position.

Risks to Maintaining Social Licence

OPG is exposed to risks associated with its social licence and public profile due to changes in the opinions of various stakeholders, including electricity customers, local communities and government agencies, Rights Holders and partners.

Maintaining public trust and meeting stakeholders and partners' expectations is critical to OPG's business success. OPG focuses on maintaining its social licence and corporate reputation through safe, reliable and sustainable operations as well as corporate citizenship, engagement and public education initiatives. Additionally, OPG is committed to advancing reconciliation with Indigenous communities and Indigenous people and enhancing its workplace culture by fostering excellence in ED&I practices.

An inability to maintain safe, reliable and environmentally responsible operations could negatively impact OPG's reputation and result in a loss of public support.

Indigenous Communities	The quality of OPG's relationships and the outcome of negotiations with Indigenous communities may impact OPG's project and financial performance, as well as its social licence to operate. OPG may be subject to claims by Indigenous communities. These claims may stem from projects or generation development activities, activities related to the operations of OPG including nuclear waste management, and historic operations of OPG's predecessor companies, which may have impacted Aboriginal and/or Treaty rights. These risks are partly mitigated by delivering on OPG's Indigenous Relations Policy, which sets out the Company's commitment to proactively build and maintain positive relationships with Indigenous communities, and the Company's Reconciliation Action Plan. OPG has also been successful in working collaboratively with Indigenous communities to resolve a number of past grievances and to establish commercial partnerships related to new generation development. However, the outcomes of ongoing and any future negotiations will depend on a number of factors, including legislation, regulations and precedents created by court rulings, which are subject to change over time.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. Transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions for the years ended December 31 were as follows:

	2024		2023	
(millions of dollars)	**Income**	**Expense**	**Income**	**Expense**
Hydro One				
Electricity sales	**18**	**-**	16	-
Services	**-**	**9**	-	11
Dividends	**5**	**-**	5	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**1,137**	-	646
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**1,459**	-	820
Hydroelectric gross revenue charge	**-**	**118**	-	114
OEFC				
Hydroelectric gross revenue charge	**-**	**223**	-	216
Interest expense on long-term notes	**-**	**88**	-	94
Income taxes	**-**	**377**	-	526
Property taxes	**-**	**13**	-	13
IESO				
Electricity related revenue	**6,473**	**-**	6,694	-
Fair Hydro Trust				
Interest income	**33**	**-**	33	-
	6,529	**3,424**	6,748	2,440

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of any excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at December 31, 2024 and 2023, the Nuclear Segregated Funds were reported net of amounts due to the Province of $10,236 million and $7,640 million, respectively.

Balances between OPG and its related parties as at December 31 were as follows:

(millions of dollars)	**2024**	**2023**
Receivables from related parties		
Hydro One	**3**	4
IESO – Electricity related receivables	**608**	623
Fair Hydro Trust	**4**	4
Province of Ontario	**1**	-
Loan receivable		
Fair Hydro Trust	**902**	905
Equity securities		
Hydro One shares	**159**	164
Accounts payable, accrued charges and other payables		
Hydro One	**3**	2
OEFC	**85**	82
Province of Ontario	**10**	8
IESO − Electricity related payables	**-**	1
Long-term debt (including current portion)		
Notes payable to OEFC	**2,100**	2,500

OPG may hold Province of Ontario bonds and treasury bills in the Nuclear Segregated Funds and the OPG registered pension plan. As at December 31, 2024, the Nuclear Segregated Funds held $1,740 million of Province of Ontario bonds (2023 – $1,603 million) and $8 million of Province of Ontario treasury bills (2023 – $4 million). As of December 31, 2024, the OPG registered pension plan held $327 million of Province of Ontario bonds (2023 − $336 million) and $9 million of Province of Ontario treasury bills (2023 – $5 million). These Province of Ontario bonds and treasury bills are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

INTERNAL CONTROL OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

Management, including the President and CEO and the Chief Financial Officer (CFO), are responsible for maintaining Disclosure Controls and Procedures (DC&P) and Internal Control over Financial Reporting (ICOFR). DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements in accordance with US GAAP.

There were no changes in OPG's ICOFR during the year ended December 31, 2024 that have materially affected or are reasonably likely to materially affect OPG's financial reports.

Management, including the President and CEO and the CFO, concluded that, as of December 31, 2024, OPG's DC&P and ICOFR, as defined in National Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings*, were effective.

FOURTH QUARTER

Discussion of Results

(millions of dollars) (unaudited)	Three Months Ended December 31 2024	2023
Revenue	**1,838**	1,894
Fuel expense	**289**	272
Operations, maintenance and administration expenses	**833**	817
Depreciation and amortization expenses	**335**	284
Accretion on fixed asset removal and nuclear waste management funds	**307**	293
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(280)**	(268)
Other net expenses (gains)	**38**	(91)
Earnings before interest and income taxes	**316**	587
Net interest expense	**42**	17
Income tax expense	**42**	116
Net income	**232**	454
Net income attributable to the Shareholder	**228**	450
Net income attributable to non-controlling interest [1]	**4**	4

[1] Relates to the following: 25 percent interest of Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in Lower Mattagami Limited Partnership; 33 percent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in PSS Generating Station Limited Partnership; 15 percent interest and 5 percent interest of corporations wholly owned by Six Nations of Grand River Development Corporation and the Mississaugas of the Credit First Nation, respectively, in Nanticoke Solar LP; and non-controlling interests in certain electricity generating facilities in the United States.

Net income attributable to the Shareholder for the fourth quarter was $228 million, compared to $450 million for the same quarter in 2023. Earnings before interest and income taxes were $316 million for the fourth quarter of 2024, representing a decrease of $271 million compared to the same quarter in 2023.

Significant factors that decreased EBIT:

- Net decrease in revenue of $147 million from the Regulated – Nuclear Generation business segment, as a result of lower electricity generation of 0.9 TWh and a lower nuclear base regulated price in effect during 2024. The lower electricity generation was expected and primarily due to the cessation of commercial operation of Unit 1 of the Pickering GS on October 1, 2024. An increase in revenue reflecting the impact of the new rate riders for disposition of regulatory accounts under the OEB's June 2024 decision and order approving the 2024 Settlement Agreement, effective July 1, 2024, was largely offset by a corresponding increase in the amortization expense of regulatory assets and regulatory liabilities recorded for regulatory account balances; and

- Lower EBIT of $82 million from Atura Power business segment, primarily due to the release of a previously recognized contingent liability in the fourth quarter of 2023 under a 2021 settlement agreement related to an acquisition of combined cycle plants.

Net interest expense increased by $25 million during the fourth quarter of 2024, compared to the same quarter in 2023, largely due to higher interest on the Company's long-term debt due to bond issuances during 2024.

Income tax expense decreased by $74 million during the fourth quarter of 2024, compared to the same quarter in 2023. The decrease was primarily due to the impact of lower earnings before income taxes.

Electricity Generation

OPG's electricity generation for the three months ended December 31, 2024 and 2023 was as follows:

(TWh)	Three Months Ended December 31 2024	2023
Regulated – Nuclear Generation	**8.3**	9.2
Regulated – Hydroelectric Generation	**7.9**	7.8
Contracted Hydroelectric and Other Generation [1]	**1.2**	1.2
Atura Power	**3.0**	2.6
Total OPG electricity generation	**20.4**	20.8

[1] Includes OPG's proportionate share of electricity generation from co-owned and minority shareholdings in electricity generating facilities.

The decrease in OPG's total electricity generation of 0.4 TWh during the fourth quarter of 2024, compared to the same quarter in 2023, was primarily due to lower electricity generation of 0.9 TWh from the Regulated – Nuclear Generation business segment as a result of the cessation of commercial operation of Unit 1 of the Pickering GS on October 1, 2024, partially offset by fewer planned outage days at the Pickering GS, and higher electricity generation from the Atura Power business segment, primarily due to higher demand for electricity generation from the combined cycle plants.

Ontario's electricity demand as reported by the IESO was 35.0 TWh during the fourth quarter of 2024, compared to 34.5 TWh for the same period in 2023. Ontario's electricity demand excludes electricity exports out of the province.

Liquidity and Capital Resources

Cash flow provided by operating activities during the three months ended December 31, 2024 was $429 million, compared to $657 million for the same period in 2023. The decrease was primarily due to lower revenue receipts from the Regulated – Nuclear Generation business segment and higher OM&A expenditures, mainly offset by higher revenue receipts from the Regulated – Hydroelectric Generation business segment and lower income tax installment payments.

Cash flow used in investing activities was $992 million during the three months ended December 31, 2024, compared to $906 million during the same period in 2023. This increase was primarily due to increased capital expenditures for the Pickering Refurbishment project and DNNP within the Regulated – Nuclear Generation business segment during the fourth quarter of 2024.

Cash flow used in financing activities increased by $129 million during the three months ended December 31, 2024, compared to the same period in 2023. The increase was primarily due to a net repayment of short-term debt, mainly offset by a higher net issuance of long-term debt.

QUARTERLY AND ANNUAL FINANCIAL HIGHLIGHTS

The following tables set out selected annual financial information for the last three years and financial information for each of the eight most recently completed quarters. This information is derived from OPG's unaudited interim consolidated financial statements and the audited annual consolidated financial statements, and has been prepared in accordance with US GAAP.

Annual Financial Information

(millions of dollars – except where noted)	**2024**	**2023**	**2022**
Revenue	**7,187**	7,434	7,349
Net income attributable to the Shareholder	**988**	1,741	1,636
Earnings per share, attributable to the Shareholder *(dollars)*	**$3.60**	$6.34	$5.96
Total assets	**68,976**	65,688	62,343
Total long-term liabilities	**44,044**	42,434	41,259
Weighted average shares outstanding *(millions)*	**274.6**	274.6	274.6

Quarterly Financial Information

	2024 Quarters Ended				
(millions of dollars – except where noted) *(unaudited)*	**December 31**	**September 30**	**June 30**	**March 31**	**Total**
Electricity generation (*TWh*)	**20.4**	**21.7**	**18.9**	**21.1**	**82.1**
Revenue	**1,838**	**1,891**	**1,691**	**1,767**	**7,187**
Net income	**232**	**383**	**166**	**225**	**1,006**
Less: Net income attributable to non-controlling interest	**4**	**4**	**6**	**4**	**18**
Net income attributable to the Shareholder	**228**	**379**	**160**	**221**	**988**
Earnings per share, attributable to the Shareholder *(dollars)*	**$0.83**	**$1.38**	**$0.58**	**$0.80**	**$3.60**

	2023 Quarters Ended				
(millions of dollars – except where noted) *(unaudited)*	**December 31**	**September 30**	**June 30**	**March 31**	**Total**
Electricity generation (*TWh*)	20.8	20.9	19.5	19.7	80.9
Revenue	1,894	1,882	1,828	1,830	7,434
Net income	454	449	423	433	1,759
Less: Net income attributable to non-controlling interest	4	5	5	4	18
Net income attributable to the Shareholder	450	444	418	429	1,741
Earnings per share, attributable to the Shareholder *(dollars)*	$1.64	$1.62	$1.52	$1.56	$6.34

Trends

OPG's quarterly electricity generation and the financial results of the Regulated – Nuclear Generation business segment are primarily impacted by outage activities at the nuclear generating stations. The frequency and timing of planned outages under a station's maintenance outage cycle and the timing of refurbishment activities may result in period-over-period variability in OPG's financial results. The maintenance outage cycle at each of OPG's nuclear generating stations determines the number of planned outages in a particular year. Outage cycles are designed to ensure continued safe and reliable long-term operations of the stations and their compliance with the CNSC's regulatory requirements.

The Darlington and Pickering nuclear generating stations have been designed to operate at full power as baseload generating facilities and therefore their electricity production does not vary with changes in grid-supplied electricity demand.

OPG's quarterly electricity generation from the Regulated – Hydroelectric Generation, Contracted Hydroelectric and Other Generation, and Atura Power business segments is affected by changes in grid-supplied electricity demand. Changes in grid-supplied electricity demand are primarily caused by variations in seasonal weather conditions, changes in economic conditions, the impact of small-scale generation embedded in distribution networks, and the impact of conservation efforts. Historically, there has been greater electricity demand in Ontario during the winter and summer months due to heating and air conditioning demands. The financial impact of forgone hydroelectric electricity generation from the Regulated – Hydroelectric Generation business segment due to SBG conditions is mitigated by a regulatory account.

OPG's quarterly electricity generation from hydroelectric facilities is impacted by weather conditions that affect water flows. Historically, there have been higher water flows in the second quarter as a result of snow and ice melt entering the river systems. The financial impact of variability in water flows on the Regulated – Hydroelectric Generation business segment is mitigated by regulatory accounts.

The financial impact of variability in electricity generation from the Contracted Hydroelectric and Other Generation business segment and the Atura Power business segment is mitigated by the terms of the applicable ESAs with the IESO for the contracted generating facilities in Ontario.

KEY OPERATING PERFORMANCE INDICATORS AND NON-GAAP FINANCIAL MEASURES

Key Operating Performance Measures

OPG evaluates the performance of its generating stations using a number of key indicators. Key operating performance indicators aligned with corporate business imperatives include measures of production reliability, cost effectiveness, environmental performance and safety performance. Certain of the measures used vary depending on the generating technology.

Nuclear Unit Capability Factor

The nuclear Unit Capability Factor is a key measure of nuclear station performance. It measures the amount of energy that the unit(s) generated over a period of time, adjusted for externally imposed constraints such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation. Capability factors are primarily affected by planned and unplanned outages. An outage day represents a single unit being offline or derated for an amount of time equivalent to one day. By industry definition, capability factors exclude production losses beyond plant management's control, such as grid-related unavailability. The nuclear Unit Capability Factor also excludes unit(s) during the period in which they are undergoing refurbishment.

Hydroelectric Availability

Hydroelectric Availability represents the percentage of time the generating unit is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period, weighted by unit capacity.

Thermal Equivalent Forced Outage Rate

Equivalent forced outage rate is an index of the reliability of a generating unit at OPG's wholly-owned thermal stations. It is measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

Thermal Availability

Thermal Availability represents the percentage of time a generating unit at Atura Power's combined cycle plants is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period, averaged by the number of facilities owned and operated through Atura Power. The measure is calculated on a three-year rolling average basis.

Other Key Indicators

OPG has also identified certain environmental and safety performance measures, which are discussed in the section, *Environmental, Social, Governance and Sustainability*.

Non-GAAP Financial Performance Measures

In addition to net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in this MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance and ensure availability of cost-effective funding. These non-GAAP financial measures have not been presented as an alternative to net income or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) Earnings before interest, income taxes, depreciation and amortization is defined as net income before net interest expense, income tax expense and depreciation and amortization expenses.

(2) Gross margin is defined as revenue less fuel expense.

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ONTARIO POWER GENERATION INC.

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2024

ONTARIO POWER GENERATION

STATEMENT OF MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

Ontario Power Generation Inc.'s (OPG or the Company) Management and Board of Directors are responsible for the presentation and preparation of the annual consolidated financial statements.

The consolidated financial statements have been prepared in accordance with United States generally accepted accounting principles (US GAAP). The consolidated financial statements necessarily include amounts based on informed judgments and estimates of the expected effects of current events and transactions with appropriate consideration to materiality. Something is considered material if it is reasonably expected to have a significant impact on the Company's earnings, cash flow, value of an asset or liability or reputation.

The Company maintains and relies on a system of internal controls to ensure, on a reasonable and cost-effective basis, reliability of the financial information. These controls are designed to provide the Company with reasonable assurance that the financial records are reliable for preparing consolidated financial statements and other financial information, assets are safeguarded against unauthorized use or disposition, liabilities are recognized and compliance with all regulatory requirements is achieved.

The consolidated financial statements have been audited by Ernst & Young LLP, independent external auditors appointed by the Board of Directors. Their Independent Auditor's Report outlines the auditor's responsibilities and the scope of their examination and their opinion on OPG's consolidated financial statements. The independent external auditor, as confirmed by the Audit and Risk Committee, had direct and full access to the Audit and Risk Committee, with and without the presence of management, to discuss their audit and their findings therefrom, as to the integrity of OPG's financial reporting and the effectiveness of the system of internal controls.

Nicolle Butcher (signed)

President and Chief Executive Officer

Aida Cipolla (signed)

Chief Financial Officer and Corporate Services Officer

March 4, 2025

INDEPENDENT AUDITOR'S REPORT

To the Shareholder of Ontario Power Generation Inc.

Opinion

We have audited the consolidated financial statements of Ontario Power Generation Inc. and its subsidiaries (the Company), which comprise the consolidated balance sheets as at December 31, 2024 and 2023, and the consolidated statements of income, consolidated statements of comprehensive income, consolidated statements of changes in shareholder's equity and consolidated statements of cash flows for the years then ended, and notes to the consolidated financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2024 and 2023, and the consolidated results of its operations and its consolidated cash flows for the years then ended in accordance with United States generally accepted accounting principles.

Basis for opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Other information

Management is responsible for the other information. The other information comprises:

- Management's Discussion and Analysis
- The information, other than the consolidated financial statements and our auditor's report thereon, in the Integrated Environmental Social and Governance and Annual Report

Our opinion on the consolidated financial statements does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information, and in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

We obtained Management's Discussion and Analysis prior to the date of this auditor's report. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact in this auditor's report. We have nothing to report in this regard.

The Annual Report is expected to be made available to us after the date of the auditor's report. If based on the work we will perform on this other information, we conclude there is a material misstatement of other information, we are required to report that fact to those charged with governance.

Responsibilities of management and those charged with governance for the consolidated financial statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with United States generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the consolidated financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's responsibilities for the audit of the consolidated financial statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these consolidated financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the consolidated financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

- Plan and perform the group audit to obtain sufficient appropriate audit evidence regarding the financial information of the entities or business units within the Group as a basis for forming an opinion on the consolidated financial statements. We are responsible for the direction, supervision and review of the work performed for the purposes of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

/s/ Ernst & Young LLP

Toronto, Canada
March 4, 2025

Chartered Professional Accountants
Licensed Public Accountants

CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31 *(millions of dollars except where noted)*	**2024**	**2023**
Revenue	**7,187**	7,434
Fuel expense	**1,049**	974
Gross margin	**6,138**	6,460
Operations, maintenance and administration expenses	**3,318**	3,136
Depreciation and amortization expenses *(Note 6)*	**1,270**	1,071
Accretion on fixed asset removal and nuclear waste management liabilities *(Note 11)*	**1,221**	1,178
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 11)*	**(1,102)**	(1,057)
Property taxes	**50**	48
	4,757	4,376
Income before other losses (gains), interest and income taxes	**1,381**	2,084
Other losses (gains)	**19**	(114)
Income before interest and income taxes	**1,362**	2,198
Net interest expense *(Note 9)*	**186**	103
Income before income taxes	**1,176**	2,095
Income tax expense *(Note 12)*	**170**	336
Net income	**1,006**	1,759
Net income attributable to the Shareholder	**988**	1,741
Net income attributable to non-controlling interest	**18**	18
Basic and diluted earnings per share *(dollars) (Note 18)*	**3.60**	6.34

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31 *(millions of dollars)*	**2024**	**2023**
Net income	**1,006**	1,759
Other comprehensive income (loss), net of income taxes *(Note 13)*		
Actuarial gain (loss), net of past service costs, on remeasurement of liabilities for pension and other post-employment benefits [1]	**41**	(109)
Reclassification to income of amounts related to pension and other post-employment benefits [2]	**(2)**	(4)
Reclassification to income of amounts related to derivatives designated as cash flow hedges [3]	**(5)**	4
Net gain on derivatives designated as cash flow hedges [4]	**1**	11
Currency translation adjustment	**173**	(45)
Other comprehensive income (loss) for the year	**208**	(143)
Comprehensive income	**1,214**	1,616
Comprehensive income attributable to the Shareholder	**1,196**	1,598
Comprehensive income attributable to non-controlling interest	**18**	18

[1] Net of income tax expense of $13 million and net of income tax recovery of $36 million for 2024 and 2023, respectively.
[2] Net of income tax recovery of nil and $1 million for 2024 and 2023, respectively.
[3] Net of income tax recovery of $2 million and net of income tax expense of $2 million for 2024 and 2023, respectively.
[4] Net of income tax expense of nil and $4 million for 2024 and 2023, respectively.

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(millions of dollars)*	2024	2023
Operating activities		
Net income	**1,006**	1,759
Adjust for non-cash items:		
Depreciation and amortization expenses *(Note 6)*	**1,270**	1,071
Accretion on fixed asset removal and nuclear waste management liabilities	**1,221**	1,178
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(1,102)**	(1,057)
Pension and other post-employment benefit costs *(Note 14)*	**361**	370
Deferred income tax expense *(Note 12)*	**39**	82
Regulatory assets and regulatory liabilities	**(23)**	(230)
Other losses (gains)	**22**	(104)
Other	**(19)**	18
Expenditures on fixed asset removal and nuclear waste management	**(529)**	(436)
Reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management	**252**	198
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	**(342)**	(300)
Net changes to other long-term assets and long-term liabilities	**116**	103
Net changes in non-cash working capital balances *(Note 22)*	**(61)**	(114)
Cash flow provided by operating activities	**2,211**	2,538
Investing activities		
Investment in property, plant and equipment and intangible assets *(Note 20)*	**(3,537)**	(2,901)
Acquisition of Lightstar Renewables and Lightstar Operations One *(Note 4)*	**(131)**	-
Purchase of new corporate headquarters real estate site *(Note 24)*	**-**	(102)
Proceeds from sale of non-core real estate site	**-**	34
Cash flow used in investing activities	**(3,668)**	(2,969)
Financing activities		
Issuance of short-term debt *(Note 10)*	**2,960**	970
Repayment of short-term debt *(Note 10)*	**(2,945)**	(835)
Issuance of long-term debt *(Note 9)*	**1,930**	244
Repayment of long-term debt *(Note 9)*	**(603)**	(43)
Equity investment from non-controlling interest	**3**	3
Distribution to non-controlling interest	**(19)**	(19)
Cash flow provided by financing activities	**1,326**	320
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**13**	(3)
Net decrease in cash, cash equivalents and restricted cash	**(118)**	(114)
Cash, cash equivalents and restricted cash, beginning of year	**1,481**	1,595
Cash, cash equivalents and restricted cash, end of year	**1,363**	1,481

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	2024	2023
Assets		
Current assets		
Cash, cash equivalents and restricted cash *(Note 5)*	**1,363**	1,481
Equity securities *(Note 21)*	**159**	164
Receivables from related parties *(Note 21)*	**616**	631
Nuclear fixed asset removal and nuclear waste management funds *(Note 11)*	**283**	68
Fuel inventory	**297**	295
Materials and supplies	**145**	106
Regulatory assets *(Note 7)*	**540**	143
Prepaid expenses	**292**	321
Other current assets	**388**	342
	4,083	3,551
Property, plant and equipment *(Note 6)*	**51,290**	47,339
Less: accumulated depreciation	**15,159**	13,879
	36,131	33,460
Intangible assets *(Note 6)*	**1,029**	802
Less: accumulated amortization	**439**	310
	590	492
Goodwill *(Note 8)*	**230**	168
Other assets		
Nuclear fixed asset removal and nuclear waste management funds *(Note 11)*	**22,129**	21,495
Loan receivable from related party *(Note 21)*	**902**	905
Long-term materials and supplies	**355**	382
Regulatory assets *(Note 7)*	**4,367**	5,078
Investments subject to significant influence	**52**	53
Other long-term assets	**137**	104
	27,942	28,017
	68,976	65,688

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	2024	2023
Liabilities		
Current liabilities		
Accounts payable, accrued charges and other payables	**2,068**	1,729
Short-term debt *(Note 10)*	**215**	200
Long-term debt due within one year *(Note 9)*	**604**	603
Regulatory liabilities *(Note 7)*	**246**	131
	3,133	2,663
Long-term debt *(Note 9)*	**11,103**	9,739
Other liabilities		
Fixed asset removal and nuclear waste management liabilities *(Note 11)*	**26,042**	25,386
Pension liabilities *(Note 14)*	**46**	883
Other post-employment benefit liabilities *(Note 14)*	**2,716**	2,641
Long-term accounts payable and accrued charges	**382**	247
Deferred revenue	**355**	364
Deferred income taxes *(Note 12)*	**2,461**	2,149
Regulatory liabilities *(Note 7)*	**939**	1,025
	32,941	32,695
Equity		
Common shares [1] *(Note 17)*	**5,126**	5,126
Class A shares [2] *(Note 17)*	**787**	787
Contributed surplus	**28**	30
Retained earnings	**15,469**	14,481
Accumulated other comprehensive income (loss) *(Note 13)*	**193**	(15)
Equity attributable to the Shareholder	**21,603**	20,409
Equity attributable to non-controlling interest	**196**	182
Total equity	**21,799**	20,591
	68,976	65,688

[1] 256,300,010 common shares outstanding at a stated value of $5,126 million as at December 31, 2024 and 2023.
[2] 18,343,815 Class A shares outstanding at a stated value of $787 million as at December 31, 2024 and 2023.

Commitments and contingencies *(Notes 9, 10, 12, 14 and 19)*

See accompanying notes to the consolidated financial statements

On behalf of the Board of Directors:

Wendy Kei (signed)
Board Chair

Jill Pepall (signed)
Director

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

Years Ended December 31 *(millions of dollars)*	**2024**	**2023**
Common shares *(Note 17)*	**5,126**	5,126
Class A shares *(Note 17)*	**787**	787
Contributed surplus		
Balance at beginning of year	**30**	32
Reclassification to income of amounts related to gain on deconsolidation of Fair Hydro Trust	**(2)**	(2)
Balance at end of year	**28**	30
Retained earnings		
Balance at beginning of year	**14,481**	12,740
Net income attributable to the Shareholder	**988**	1,741
Balance at end of year	**15,469**	14,481
Accumulated other comprehensive income (loss), net of income taxes *(Note 13)*		
Balance at beginning of year	**(15)**	128
Other comprehensive income (loss)	**208**	(143)
Balance at end of year	**193**	(15)
Equity attributable to the Shareholder	**21,603**	20,409
Equity attributable to non-controlling interest		
Balance at beginning of year	**182**	176
Income attributable to non-controlling interest	**18**	18
Equity investment from non-controlling interest *(Note 23)*	**15**	7
Distribution to non-controlling interest	**(19)**	(19)
Balance at end of year	**196**	182
Total equity	**21,799**	20,591

See accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. DESCRIPTION OF BUSINESS

Ontario Power Generation Inc. (OPG or the Company) was incorporated on December 1, 1998 pursuant to the *Business Corporations Act* (Ontario) and is wholly-owned by the Province of Ontario (the Province or the Shareholder). OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity.

Unless the context indicates otherwise, references in the consolidated financial statements to “the Company”, or “OPG” are made to Ontario Power Generation Inc. and its subsidiaries.

As at December 31, 2024, OPG owned and operated two nuclear generating stations, 66 hydroelectric generating stations, two thermal generating stations, one solar facility and four combined cycle gas turbine (combined cycle) plants in Ontario, Canada. The combined cycle plants are natural gas-fired facilities owned and operated through the Company’s wholly-owned subsidiary operating as Atura Power. Through its United States (US)-based wholly-owned subsidiary, OPG Eagle Creek Holdings LLC (Eagle Creek), OPG also wholly or jointly owned and operated 85 hydroelectric generating stations and held minority interests in 14 hydroelectric and two solar facilities in the US as at December 31, 2024. In addition, OPG owns two nuclear generating stations in Ontario, the Bruce A generating station (GS) and the Bruce B GS (together, the Bruce nuclear generating stations), which are leased on a long-term basis to Bruce Power L.P. (Bruce Power).

2. BASIS OF PRESENTATION

These consolidated financial statements have been prepared and presented in accordance with United States generally accepted accounting principles (US GAAP).

As required by *Ontario Regulation 395/11,* as amended, under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the Ontario Securities Commission (OSC) from the requirements of section 3.2 of National Instrument 52-107, *Acceptable Accounting Policies and Auditing Standards*. The exemption allows OPG to file consolidated financial statements prepared in accordance with US GAAP, rather than International Financial Reporting Standards (IFRS), without becoming a US Securities and Exchange Commission registrant.

In September 2022, OPG received an extension to its previous exemptive relief from the OSC. The exemptive relief will terminate on the earliest of the following:

- January 1, 2027;
- The financial year that commences after OPG ceases to have activities subject to rate regulation; and
- The financial year that commences on or following the later of:
    I. The effective date prescribed by the International Accounting Standards Board (IASB) for the mandatory application of a standard within IFRS specific to entities with rate regulated activities (Mandatory Rate-regulated Standard); and
    II. Two years after the IASB publishes the final version of a Mandatory Rate-regulated Standard.

All dollar amounts are presented in Canadian dollars, unless otherwise noted. Certain 2023 comparative amounts have been reclassified from consolidated financial statements previously presented to conform to the 2024 consolidated financial statement presentation.

3. SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

a) Basis of Consolidation

The consolidated financial statements of the Company include the accounts of OPG and its majority-owned subsidiaries and variable interest entities (VIEs) where OPG is the primary beneficiary. All intercompany balances and intercompany transactions are eliminated on consolidation.

Where OPG does not control an investment but has significant influence over operating and financing policies of the investee, the investment is accounted for under the equity method.

Outlined below is information related to OPG's investments which are accounted for under the equity method as at December 31, 2024:

Entity	Place of Business	Entity Type	Ownership Interest
Ontario Charging Network L.P. [1]	Canada	Limited Partnership	50.00%
South Fork II Associates, L.P.	United States	Limited Partnership	50.00%
Concord Hydro Associates	United States	Limited Partnership	26.94%
New Hampshire Hydro Associates	United States	Partnership	27.08%
North Hartland, LLC	United States	Limited Liability Company	26.80%
Dodge Falls Associates, L.P.	United States	Limited Partnership	26.80%
Mesalonskee Stream Hydro, LLC	United States	Limited Liability Company	26.80%
HCE-Dodge Falls, Inc.	United States	Corporation	26.94%
Benton Falls Associates	United States	Partnership	27.08%
HMG, LLC	United States	Limited Liability Company	33.00%
Boltonville Hydro Associates	United States	Partnership	11.25%
Briar Hydro Associates	United States	Partnership	27.08%
Brassua TIC	United States	Tenancy-in-Common	24.19%
Kennebec Water Power Company	United States	Corporation	50.20%

[1] In the first quarter of 2025, OPG entered into an agreement to divest its interest in Ontario Charging Network L.P (operating as Ivy Charging Network) to Hydro One Limited. The transaction was completed during the same quarter.

b) Variable Interest Entities

OPG performs ongoing analysis to assess whether it holds any VIEs. VIEs of which OPG is deemed to be the primary beneficiary are consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the Company. In circumstances where OPG is not deemed to be the primary beneficiary, the VIE is not recorded in OPG's consolidated financial statements. VIEs are deconsolidated when facts and circumstances arise which indicate that OPG is no longer deemed to be the primary beneficiary.

As of December 31, 2024, the Company's significant VIE was the Nuclear Waste Management Organization (NWMO).

Nuclear Waste Management Organization

In 2002, OPG and other Canadian used nuclear fuel producers established a separately incorporated NWMO in accordance with the *Nuclear Fuel Waste Act* (Canada) (NFWA). The primary long-term mandate of the NWMO is to implement an approach to address the long-term management of used nuclear fuel in Canada. OPG has the majority of voting rights at the NWMO Board of Directors' and members' level. The NFWA requires the used nuclear fuel owners to establish and make payments into trust funds for the purpose of funding the implementation of the long-term used nuclear fuel management plan in accordance with the NFWA. OPG provides over 90 percent of the NWMO's funding, primarily towards the design and implementation of Canada's Adaptive Phased Management (APM) plan for the long-term management of used nuclear fuel. As a result, OPG is expected to absorb a majority of the NWMO's expected

losses through future funding in the event of any shortfall. Therefore, OPG holds a variable interest in the NWMO, of which it is the primary beneficiary. Accordingly, the applicable amounts in the accounts of the NWMO, after elimination of intercompany transactions, are consolidated.

c) Use of Management Estimates

The preparation of consolidated financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the end of the reporting period, and the reported amounts of revenues and expenses for the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions and assumptions believed to be reasonable at the time the estimate is made, with any adjustments recognized in the period incurred. Significant estimates are included in the determination of pension and other post-employment benefits (OPEB) balances, asset retirement obligations (AROs) and associated asset retirement costs capitalized as part of property, plant and equipment (PP&E), income taxes (including deferred income taxes), contingencies, regulatory assets and regulatory liabilities, goodwill and intangible assets, valuation of investments in segregated funds, depreciation and amortization expenses and inventories. Actual results may differ significantly from these estimates.

d) Business Combinations

The Company accounts for acquisitions of entities or assets that meet the definition of a business as business combinations. Business combinations are accounted for using the acquisition method. Assets acquired and liabilities assumed in business combinations are measured at their fair value at the acquisition date. Acquisition costs incurred in connection with business combinations are expensed in the period incurred. When a set of activities acquired does not represent a business, the transaction is accounted for as an asset acquisition and acquisition costs are capitalized.

Intangible assets acquired in business combinations are recognized separately at fair value if they arise from contractual or other legal rights or are separable.

e) Goodwill

Goodwill represents the excess of the purchase price of an acquired business over the fair value of the assets acquired and liabilities assumed.

The Company allocates goodwill to operating segments that are expected to benefit from the goodwill recognized. At least once a year, the Company assesses qualitative and quantitative factors to determine whether it is more likely than not that the fair value of a reporting unit to which goodwill is attributed is less than its carrying amount. If it is more likely than not that a reporting unit's fair value is less than its carrying amount or if a quantitative assessment is elected, the Company calculates the fair value of the reporting unit. The carrying amount of a reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit exceeds its fair value. Any impairment charge represents the excess of the reporting unit's carrying amount over its fair value, to the extent that the impairment charge is limited to the total amount of goodwill allocated to the reporting unit. Goodwill is tested for impairment between annual assessments if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

f) Cash, Cash Equivalents, Restricted Cash and Short-Term Investments

Cash and cash equivalents include cash on deposit and money market securities with a maturity of 90 days or less on the date of purchase. Restricted cash primarily includes amounts set aside pursuant to requirements of various debt and financing agreements. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments and classified as current assets. These securities are valued at the lower of cost and market value.

g) Loan Receivables

Loan receivables are financial assets with fixed or determined payments that are not quoted in an active market. Loan receivables are initially recorded at fair value, and subsequently recorded at amortized cost using the effective interest method. The loan receivable balance relates to the subordinated notes issued by the Fair Hydro Trust to OPG. The balance was recognized by OPG following the deconsolidation of the Fair Hydro Trust as a result of the *Fixing the Hydro Mess Act, 2019.*

h) Inventories

Inventories, consisting of fuel and materials and supplies, are measured at the lower of cost and net realizable value. Cost is determined as weighted average cost for fuel inventory and average cost for materials and supplies.

i) Intangible Assets

Intangible assets are recorded at cost. Intangible assets that are not considered to have an indefinite life are amortized using an amortization method that reflects the pattern in which their economic benefits are consumed or on a straight-line basis if that pattern is not readily determinable. Amortization of intangible assets is reflected in the depreciation and amortization expenses on the consolidated statements of income. Intangible assets are subject to impairment testing and if impaired, the carrying value is accordingly reduced.

As at December 31, 2024, the amortization periods of intangible assets were as follows:

Power purchasing contracts	2 to 20 years
Operating licences – Federal Energy Regulatory Commission	10 to 40 years
Major application and computer software	3 to 5 years

Power purchasing contracts are amortized on a straight-line basis over the remaining terms of the respective contracts. Operating licences are amortized on a straight-line basis over the remaining terms of the respective licences.

j) Property, Plant and Equipment and Depreciation

PP&E is recorded at cost. Interest costs incurred during construction are capitalized as part of the cost of the asset based on the interest rates on OPG's long-term debt. Expenditures for replacements of major components are capitalized.

Major maintenance expenditures for combined cycle plants under long-term service agreements with third parties are accounted for using the deferral method, whereby the costs are capitalized and depreciated over their estimated useful life. Repairs and other maintenance costs are expensed when incurred.

Asset removal costs that have not been specifically provided for in current or previous periods are charged to operations, maintenance and administration (OM&A) expenses when incurred.

Depreciation rates for the various classes of assets are based on their estimated service lives. PP&E are depreciated on a straight-line basis, except for computer equipment, which are depreciated on a declining balance basis.

As at December 31, 2024, the depreciation periods of PP&E were as follows:

Nuclear generating stations and major components	5 to 87 years [1]
Hydroelectric generating stations and major components	3 to 100 years
Thermal generating stations and major components	5 to 50 years
Administration and service facilities	5 to 50 years
Computer equipment	40% per year
Service equipment	3 to 15 years

[1] As at December 31, 2024, the end of station life for depreciation purposes for the Darlington, Units 5 to 8 of the Pickering, Bruce A and Bruce B nuclear generating stations ranged between 2052 and 2070. Major components are depreciated over the lesser of the station life and the life of the components. Units 1 to 4 of the Pickering nuclear generating station have been permanently shut down and have been or are being placed in a safe storage state.

The accounting estimates related to end-of-life assumptions for PP&E require significant management judgment, including consideration of various operating, technological and economic factors. OPG reviews the estimated useful lives for its PP&E, including end-of-life assumptions for major generating assets, on a regular basis.

For nuclear generating stations operated by OPG, establishing station end-of-life assumptions primarily involves an assessment of operating lives of major life-limiting components such as fuel channel assemblies, taking into account expectations of future ability to economically operate and, as appropriate, refurbish the station for continued use. Expected operating lives of major life-limiting components are established through technical assessments of their fitness-for-service. Expectations of future ability to operate the station may be affected by operating licence requirements, ability to recover capital, operating and decommissioning costs and government policy, among other factors.

Although there is a link between the age of a hydroelectric generating facility and the capital investment required to maintain that facility, age does not generally establish an overall upper limit on the expected useful life of a hydroelectric generating station. Regular maintenance and the replacement of specific components typically allow hydroelectric stations to operate for very long periods. An estimated useful life not exceeding 100 years is used by OPG to depreciate dams and other major hydroelectric station structures.

Station end-of-life assumptions for thermal and solar generating assets are established based on operating life expectations of major components and expectations of future ability to economically operate the station taking into consideration available revenue mechanisms.

k) Asset Impairment

Long-lived assets with defined lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The review is based on the presence of impairment indicators such as the future economic benefit of the assets and external market conditions. The net carrying amount of assets is considered impaired if it exceeds the sum of the estimated undiscounted cash flows expected to result from the asset's use and eventual disposition. In cases where the sum of the undiscounted expected future cash flows is less than the carrying amount, an impairment loss is recognized. This loss equals the amount, if any, by which the carrying amount exceeds the fair value. Fair value is determined using expected discounted cash flows when quoted market prices are not available. The impairment is recognized in income in the period in which it is identified.

The carrying values of investments accounted for under the equity method are reviewed annually for the presence of any indicators of impairment. If an impairment exists and is determined to be other-than-temporary, an impairment charge is recognized. This charge equals the amount by which the carrying value exceeds the investment's fair value.

l) Rate Regulated Accounting

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that OPG receives regulated prices for electricity generated from the 54 prescribed hydroelectric generating stations and the Darlington and Pickering nuclear generating stations located in Ontario. OPG's regulated prices for these facilities are determined by the Ontario Energy Board (OEB).

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998*, the *Electricity Act, 1998* and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Ontario Ministry of Energy and Electrification. It regulates market participants in Ontario's natural gas and electricity industries. The OEB carries out its regulatory functions through public hearings and other more informal processes such as consultations.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required by the regulator to be obtained from, or settled with, the customers. When the Company assesses that there is sufficient assurance that incurred costs in respect of its generating facilities prescribed for economic regulation by the OEB (regulated facilities) will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the Company is required to refund amounts to customers in the future in respect of the regulated facilities, including amounts related to costs that have not been incurred and for which the OEB has provided recovery through regulated prices, the Company records a regulatory liability.

Certain regulatory assets and regulatory liabilities recognized by the Company relate to deferral and variance accounts (regulatory accounts) authorized by the OEB, or *Ontario Regulation 53/05*. The measurement of these regulatory assets and regulatory liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

Regulatory assets and regulatory liabilities for regulatory account balances approved by the OEB for inclusion in regulated prices are amortized based on approved recovery or repayment periods.

In addition to regulatory assets and regulatory liabilities for regulatory accounts, OPG recognizes regulatory assets and regulatory liabilities for unamortized amounts recorded in accumulated other comprehensive income or loss (AOCI) in respect of pension and OPEB obligations, deferred income taxes, and, as applicable, differences between interim regulated prices charged to customers during an interim rate period and final regulated prices authorized or to be authorized by the OEB for that period, to reflect the expected recovery or repayment of these amounts through future regulated prices to be charged to customers. There are measurement uncertainties related to these balances due to the assumptions made in the determination of pension and OPEB obligations and deferred income taxes that are attributed to the regulated business segments, and assumptions made with respect to final regulated prices to be authorized by the OEB for an interim rate period.

The regulatory assets and regulatory liabilities recognized by the Company for unamortized pension and OPEB amounts recorded in AOCI has reflected the OEB's use, since April 1, 2008, of the accrual basis of accounting for including pension and OPEB amounts in approved regulated prices for OPG. This is also the manner in which these costs are recognized in OPG's consolidated financial statements. Therefore, unamortized amounts in respect of OPG's pension and OPEB plans recognized in AOCI generally would not be reflected in regulated prices until they have been reclassified from AOCI and recognized as amortization components of the benefit costs for these plans. The regulatory assets and regulatory liabilities are reduced as underlying unamortized balances are amortized as components of the benefit cost.

For the period from November 1, 2014 to December 31, 2021, the OEB limited amounts for pension and OPEB costs included in the nuclear and hydroelectric regulated prices to the respective regulated business' portions of the Company's cash expenditures for its pension and OPEB plans. The differences between actual pension and OPEB

costs determined using the accrual method applied in OPG's consolidated financial statements and OPG's actual cash expenditures for these plans were captured in the OEB-authorized Pension & OPEB Cash Versus Accrual Differential Deferral Account for future consideration by the OEB.

In 2017, the OEB issued a report outlining the guiding principles and policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report established the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility.

The OEB's February 2019 decision and order approving the proposed settlement reached by OPG and intervenors on OPG's August 2018 application to disposition regulatory accounts resulted in approval to recover the balance recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account as of December 31, 2017, without adjustments. In making that decision and order, the OEB approved that the accrual method was the appropriate regulatory accounting and cost recovery basis for the December 31, 2017 pension and OPEB-related balances in the Pension & OPEB Cash Versus Accrual Differential Deferral Account.

In the second half of 2021, the OEB issued decisions approving a proposed settlement reached by OPG and intervenors on most of the issues in OPG's 2022-2026 application for new regulated prices (2021 Settlement Agreement). The 2021 Settlement Agreement provided for recovery of pension and OPEB costs in the nuclear revenue requirements using the accrual method of accounting, with the differences between actual pension and OPEB costs determined under this method and corresponding forecast amounts reflected in the approved revenue requirements to be recorded in the Pension and OPEB Cost Variance Account for subsequent review and approval by the OEB. For the hydroelectric facilities, the Pension & OPEB Cash Versus Accrual Differential Deferral Account continues to record the differences between actual pension and OPEB costs determined using the accrual method and actual cash expenditures for these plans. The 2021 Settlement Agreement and the OEB's June 2024 decision and order approving the proposed complete settlement on OPG's December 2023 application to disposition regulatory accounts reached by OPG and intervenors (2024 Settlement Agreement) provided for recovery of the balance recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account as of December 31, 2019 and December 31, 2022, respectively, without adjustments. Further details on the 2024 Settlement Agreement can be found in Note 7.

It is the Company's position that the above outcomes have collectively established the accrual basis of accounting as the default method of determining pension and OPEB amounts for rate-setting purposes and that there is sufficient likelihood that unamortized pension and OPEB amounts that have not yet been reclassified from AOCI, as well as amounts recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account subsequent to December 31, 2022, will be included in future regulated prices. Therefore, the Company continues to recognize regulatory assets and regulatory liabilities for these balances.

m) Revenue Recognition

i) Revenue from Contracts with Customers – Regulated Generation

Provided OPG maintains a valid generation licence from the OEB and continues to remain in compliance with the Independent Electricity System Operator's (IESO) Market Rules, its regulated nuclear and regulated hydroelectric generating facilities can continue to offer electricity into the wholesale energy market. OPG's generation licence was renewed in 2023 and is valid until October 2043. Energy revenue generated from OPG's regulated facilities is based on regulated prices determined by the OEB that include base regulated prices and, as applicable, rate riders for the recovery or repayment of approved regulatory account balances. The revenue from the regulated hydroelectric facilities is also subject to the OEB-approved hydroelectric incentive mechanism that provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers.

The majority of OPG's electricity generation is offered into Ontario's real-time energy spot market administered by the IESO. For electricity generated from its regulated nuclear and regulated hydroelectric facilities, OPG receives payment from the IESO on a monthly basis based on regulated prices authorized by the OEB. OPG's performance obligation with respect to regulated generation is to supply electricity generated from its regulated facilities to the wholesale energy market in Ontario. The Company has determined that this performance obligation is satisfied over time; OPG utilizes the output method to recognize revenue by applying the relevant base regulated price and rate riders as applicable to each unit of electricity generated and metered to the IESO. This methodology reflects the real-time nature of electricity generation and the underlying performance obligation, of which no portion remains unsatisfied at the end of the applicable reporting period.

During any interim rate periods authorized by the OEB, revenue is recognized on the basis of interim regulated prices set by the OEB. In instances where a subsequent OEB decision results in a difference between final regulated prices retroactively effective for the interim period and the interim regulated prices, OPG records the resulting adjustment to revenue in connection with that period, based on the OEB's decision, as a regulatory asset or regulatory liability. Any resulting revenue shortfall in connection with the interim rate period is collected prospectively from the IESO in the manner authorized by the OEB.

OPG's receivables for electricity generated from its regulated nuclear and regulated hydroelectric facilities are part of the Company's electricity-related receivables from the IESO, representing OPG's unconditional right to payment for satisfying its performance obligation wherein only the passage of time is required before payment is received.

Base regulated prices in effect for the period from January 1, 2022 to December 31, 2026 for OPG's regulated nuclear and regulated hydroelectric generation were established by the OEB's final payment amounts order issued in January 2022, reflecting the OEB's decisions on OPG's 2022-2026 application for new regulated prices issued in the second half of 2021. These decisions and orders confirmed the continued use of a custom incentive regulation framework for the nuclear facilities.

The base regulated price for hydroelectric electricity generation (hydroelectric base regulated price) in effect for the period from January 1, 2022 to December 31, 2026 has been set equal to the 2021 hydroelectric base regulated price pursuant to *Ontario Regulation 53/05*. For the period from June 1, 2017 to December 31, 2021, the base regulated prices for the hydroelectric facilities were determined by annually escalating the previously approved base regulated prices, with some adjustments, using an approved formula equal to an industry-specific weighted inflation factor based on indices published annually by the OEB, less a stretch factor adjustment.

The base regulated prices for nuclear electricity generation (nuclear base regulated price) are set under a rate smoothing approach that defers a portion of approved nuclear revenue requirements for future collection in the Rate Smoothing Deferral Account, with the objective of making more stable changes in OPG's overall production-weighted average regulated price year over year during the Darlington Refurbishment project period, consistent with the requirements of *Ontario Regulation 53/05*. The nuclear revenue requirement for each of the years is based on the OEB-allowed level of operating costs and a return of and on rate base, less a stretch factor adjustment. Rate base is a regulatory construct that, for OPG, represents the average net level of investment in regulated fixed and intangible assets in service and an allowance for working capital.

Further details on the Rate Smoothing Deferral Account can be found in Note 7.

ii) Revenue from Contracts with Customers – Non-regulated Generation and Other Revenue

All of OPG's non-regulated generating facilities in Ontario are subject to energy supply agreements with the IESO (ESAs).

Revenue from the generating stations subject to an ESA is recognized in the amount that OPG has a right to invoice on a monthly basis as the Company satisfies its performance obligation in accordance with the terms of the agreement to supply energy and capacity from the applicable generating facilities. No portion of OPG's performance obligation

remains unsatisfied at the end of any applicable reporting period. OPG estimates revenues for variable or conditional amounts under each ESA using a most likely amount approach on a contract-by-contract basis. Variable consideration under each ESA is included in revenue only to the extent that it is probable that the amount will not be subject to significant reversal when the underlying uncertainty is resolved.

OPG's receivables for electricity generated under ESAs with the IESO are part of the Company's electricity-related receivables from the IESO, representing OPG's unconditional right to payment for satisfying its performance obligation wherein only the passage of time is required before payment is received.

OPG's generating facilities in the US are either subject to power purchase agreements (PPAs) for the supply of energy and capacity into the respective markets, or receive wholesale market prices. The counterparties to PPAs currently in effect are primarily local government entities and local electric utilities based in the US. Depending on the contractual terms in each PPA, the performance obligation is either to supply energy, capacity, renewable energy certificates (RECs) or a combination thereof. The performance obligations to supply energy and capacity is satisfied over time, with revenue recognized in the amount the Company has a right to invoice on a monthly basis to the applicable counterparty. The performance obligation to supply RECs is satisfied at a point in time, with revenue recognized when the certificates related to the respective RECs are delivered.

OPG also sells into, and purchases from, interconnected electricity markets in other Canadian provinces and the northeast and mid-west regions of the US. Under these arrangements, OPG's performance obligation is to either physically supply energy, settle financially, or provide capacity, depending on the contract, to a counterparty in a control area outside of Ontario. Gains and losses on energy trading contracts (including those to be physically settled) are recorded on a net basis in the consolidated statements of income.

OPG also derives non-energy revenue under the terms of a lease arrangement and associated non-lease agreements with Bruce Power related to the Bruce nuclear generating stations. The associated agreements include revenue from heavy water sales, heavy water tritium removal (detritiation) services and nuclear waste management services. Revenues under these agreements are recognized as services are provided or when products are delivered, satisfying OPG's performance obligation.

In addition, non-energy revenue includes isotope sales and other service revenue. Revenue from these activities is recognized as the respective performance obligations are satisfied, in accordance with the terms stipulated in the respective contracts.

iii) Revenue Recognition – Leasing Revenue

The minimum lease payments stemming from OPG's lease arrangement with Bruce Power related to the Bruce nuclear generating stations are recognized in revenue on a straight-line basis over the term of the lease. Similarly, revenue from real estate leasing arrangements is recognized on a straight-line basis over the term of the lease as the Company renders the requisite services outlined in the respective contracts.

n) Fixed Asset Removal and Nuclear Waste Management Liabilities

OPG recognizes AROs for fixed asset removal and nuclear waste management, discounted for the time value of money. OPG estimates both the amount and timing of future cash expenditures based on the plans for fixed asset removal and nuclear waste management. The liabilities are initially recorded at their estimated fair value, which is based on a discounted value of the expected costs to be paid.

On an ongoing basis, the liabilities for nuclear fixed asset removal and nuclear waste management (Nuclear Liabilities) are increased by the present value of the incremental (variable) cost portion for the nuclear waste generated each year, with the corresponding amounts charged to expenses. Variable expenses relating to low and intermediate level irradiated materials (known as low and intermediate level waste or L&ILW) are charged to OM&A expenses. Variable expenses relating to the management and storage of used nuclear fuel are charged to fuel expense. The liabilities may

also be adjusted due to changes in the estimated amount or timing of the underlying future cash flows, with resulting changes in the related asset retirement costs capitalized as part of the carrying amount of the related fixed assets in service.

A number of significant assumptions used in the calculation of Nuclear Liabilities are subject to inherent uncertainty and judgment as nuclear fixed asset removal and nuclear waste management programs evolve. As a result, changes to the underlying operational and technical factors and other assumptions underlying these estimates could change significantly over time, and may result in material changes to increase or decrease the costs for these programs.

A comprehensive reassessment of all underlying assumptions and baseline cost estimates for the Nuclear Liabilities is performed periodically. Changes in the Nuclear Liabilities resulting from changes in assumptions or estimates that impact the amount or timing of the originally estimated undiscounted future cash flows are recorded as an adjustment to the liabilities. Upward revisions in the Nuclear Liabilities represent the present value of increases in future undiscounted cash flows determined using a current credit-adjusted risk-free rate. Downward revisions in the Nuclear Liabilities represent the present value of decreases in future undiscounted cash flows determined using the weighted average discount rate reflected in the existing liability. Upon settlement of the liabilities, a gain or loss would be recorded.

Accretion arises because the fixed asset removal and nuclear waste management liabilities are reported on a present value basis. Accretion expense is the increase in the carrying amount of the liabilities due to the passage of time.

The asset retirement cost is capitalized by increasing the carrying value of the related fixed assets in service. The capitalized cost is depreciated over the remaining service life of the related fixed assets and is included in depreciation and amortization expenses.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

o) Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

Pursuant to the Ontario Nuclear Funds Agreement (ONFA) between OPG and the Province, OPG has established and sets aside funds in a Used Fuel Segregated Fund and a Decommissioning Segregated Fund (together, the Nuclear Segregated Funds). The Used Fuel Segregated Fund is intended to fund expenditures associated with the long-term management of used nuclear fuel bundles and certain costs of used nuclear fuel storage incurred after the nuclear generating stations are shut down. The Decommissioning Segregated Fund was established to fund the costs of nuclear fixed asset removal and long-term L&ILW management, and certain costs of used nuclear fuel storage incurred after the nuclear generating stations are shut down. OPG's funding obligations and resulting contributions to the Nuclear Segregated Funds are in connection with the existing facilities and are determined based on periodically updated reference plans approved by the Province under the ONFA. OPG maintains the Nuclear Segregated Funds in third-party custodial and trust accounts that are segregated from the rest of OPG's assets.

OPG's investments in the Nuclear Segregated Funds and the corresponding amounts payable to, or receivable from the Province are classified as held-for-trading. The Nuclear Segregated Funds are measured at fair value based on the bid prices of the underlying equity and fixed income securities, and, in the case of the real assets portfolio, using appropriate valuation techniques as outlined in Note 16, with realized and unrealized gains and losses recognized in OPG's consolidated statements of income.

p) Derivatives

All derivatives are generally classified as held-for-trading and recorded at fair value in the consolidated balance sheets. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading.

Derivatives qualify for hedge accounting if they meet relevant hedging documentation requirements, and if the derivative instrument that is designated as a hedge is expected to effectively hedge the identified risk throughout the life of the hedged item. At the inception of a hedging relationship, OPG documents the relationship between the hedging instrument and the hedged item, its risk management objective and its strategy for undertaking the hedge.

A documented assessment is made, both at the inception of a hedge and on an ongoing basis, of whether or not the derivatives that are used in hedging transactions are highly effective in offsetting the changes attributable to the hedged risks in the fair values or cash flows of the hedged items.

All derivative contracts not designated as hedges are recorded as derivative assets or derivative liabilities at fair value, with changes in the fair value recorded in the consolidated statements of income. Refer to Note 15 for a discussion of OPG's risk exposures and the derivative instruments used to manage these risks.

q) Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arm's-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. OPG uses a fair value hierarchy, grouping assets and liabilities into three levels based on the relative objectivity of the inputs used to measure fair value, with Level 1 representing the most objective. Refer to Note 16 for a discussion of fair value measurements and the fair value hierarchy.

r) Equity Securities

Equity securities held by OPG are measured at fair value, with gains and losses due to changes in fair value recognized in the consolidated statements of income. Related transaction costs are expensed as incurred, and dividend income is included in net income in the period in which dividends are declared. Equity securities are initially measured at cost.

s) Foreign Currency Translation

The functional currency of all of OPG's significant subsidiaries is the Canadian dollar, except for subsidiaries based in the US, whose functional currency is the United States dollar (USD) and the Company's Romanian subsidiary, whose functional currency is the Romanian Leu. The functional currency of the Company's subsidiaries is the currency of the primary economic environment in which they operate.

Transactions in currencies other than the functional currency are translated into the functional currency at the rate of exchange prevailing at the date of the transaction. Monetary assets and monetary liabilities denominated in foreign currencies are retranslated at the functional currency rate of exchange prevailing at the consolidated balance sheet dates. Exchange gains and losses on settlement of transactions and the translation of monetary assets and monetary liabilities are recorded in the consolidated statements of income.

The results and financial position of all of the Company's subsidiaries that have a USD or Romanian Leu functional currency are translated into the presentation currency at the closing rate at the consolidated balance sheet dates for assets and liabilities and at the average exchange rate for the period for items of income and expenses. Unrealized gains or losses arising as a result of the translation of the financial information of these entities are reported as a component of other comprehensive income or loss (OCI) and are accumulated in AOCI on the consolidated balance sheets, and are not recorded in net income or retained earnings unless there is a complete or substantially complete sale or liquidation of the investment.

t) Leases

The Company determines if an arrangement is, or contains, a lease at the inception date. A contract is determined to contain a lease if it consists of an identified asset, and the customer in the arrangement has the right to control the use of the asset for a period of time in exchange for consideration. Leases are evaluated and classified as either operating or finance leases for financial reporting purposes. Finance leases, which transfer substantially all of the risks and benefits incidental to ownership of the leased item, are capitalized at the inception of the lease at the present value of the minimum lease payments. Finance leases are depreciated over the shorter of the estimated useful life of the asset and the lease term.

Leases where the lessor retains substantially all the risks and benefits incidental to ownership of the asset are classified as operating leases. Operating lease payments, other than contingent rentals, are recognized as an expense in the consolidated statements of income on a straight-line basis over the lease term. Where the amount of rent expense recognized is different from the actual operating lease payment, other than contingent rentals, the difference is deferred and included as assets or liabilities on the consolidated balance sheets.

OPG recognizes a right-of-use asset and lease liability for operating lease arrangements, other than short-term leases, in which OPG is the lessee. Short-term leases include leases that have a term of 12 months or less at the commencement date and do not contain an option to purchase the underlying asset that the entity is reasonably certain to exercise. Operating lease assets and liabilities are recognized at the lease commencement date based on the estimated present value of lease payments over the lease term. When determinable, the rate implicit in the lease is used as the discount rate to calculate the present value of the lease payments related to arrangements in which the Company is the lessee. Otherwise, the incremental borrowing rate is used. The discount rate is reassessed if the respective lease liability is required to be remeasured because of changes in key assumptions or modifications in the underlying contract.

Lease arrangements with lease and non-lease components are accounted for as a single lease component.

u) Pension and Other Post-Employment Benefits

OPG's post-employment benefit programs covering most of the regular employees include a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, other post-retirement benefits (OPRB) including group life insurance and health care benefits and long-term disability (LTD) benefits. Certain post-employment defined benefit programs are also provided by the NWMO and subsidiaries of the Company, all of which are consolidated into OPG's financial results. Certain subsidiaries of the Company sponsor defined contribution employee savings plans for eligible employees, under which each of employer and employees make contributions according to the plan terms. The OPG defined benefit pension plan is indexed to inflation, subject to certain maximums. Unless otherwise noted, information on the Company's post-employment benefit programs is presented on a consolidated basis.

OPG recognizes the funded status of its defined benefit plans on the consolidated balance sheets. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation, on a plan-by-plan basis.

The obligations for defined benefit pension and OPRB are determined using the projected benefit method pro-rated on service. The obligation for LTD benefits is determined using the projected benefit method on a terminal basis. Defined benefit pension and OPEB obligations are impacted by factors including demographic (such as mortality and retirement) and economic (such as discount rates, salary levels, inflation and health care cost escalation) assumptions, experience gains or losses, and adjustments arising from plan amendments. Defined benefit pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions.

Assumptions are significant inputs to actuarial models that measure defined benefit pension and OPEB obligations and related effects on operations. Discount rate, inflation rate and changes in salary levels are three key assumptions in the determination of benefit costs and obligations. In addition, the expected long-term rate of return on plan assets is a

key assumption in the determination of defined benefit registered pension plan cost and the health care cost trend rate is a key assumption in the determination of OPEB cost and obligations. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality and employee turnover, are evaluated periodically by management in consultation with independent actuaries. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors giving rise to actuarial gains and losses. In accordance with US GAAP, for pension and OPRB, the impact of these updates and differences on the respective benefit obligations is accumulated and amortized over future periods, as discussed below.

The discount rates, which are representative of AA corporate bond yields, are used to calculate the present value of the expected future cash flows on the measurement date in order to determine the projected benefit obligations for the Company's employee benefit plans. A lower discount rate increases the benefit obligations and increases benefit costs. OPG uses a full yield curve approach to estimate the service and interest cost components of defined benefit pension and OPEB costs, whereby specific spot rates along the yield curve used in the determination of the projected benefit obligations are applied to the relevant projected cash flows. The expected rate of return on defined benefit pension plan assets is based on the pension fund's asset allocation and the expected return considering long-term risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

Pension fund assets include domestic and international equity securities, corporate and government fixed income securities, pooled funds, real estate, infrastructure and other investments. These assets are managed by professional investment managers. The pension fund does not invest in equity or debt securities issued by OPG or its subsidiaries and partnerships. Pension fund assets of defined benefit pension plans are valued using market-related values for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value for pension fund assets of the OPG defined benefit pension plan recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

Defined benefit pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, recognition of past service costs or credits resulting from plan amendments, and recognition of actuarial gains or losses, resulting from changes in assumptions and experience gains and losses. Past service costs or credits arising from defined benefit pension and OPRB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the corresponding plan. Past service costs or credits arising from amendments to LTD benefits are immediately recognized as OPEB costs in the period incurred. Due to the long-term nature of pension and OPRB liabilities, the excess of the net cumulative unamortized gain or loss, over ten percent of the greater of the benefit obligation and the market-related value of the plan assets (the corridor) for each plan is amortized over the expected average remaining service life of the employees covered by the plan, which represents the period during which the associated economic benefits are expected to be realized by the Company. Actuarial gains or losses for LTD benefits are immediately recognized as OPEB costs in the period incurred.

Actuarial gains or losses and past service costs or credits arising during the year that are not recognized immediately as components of defined benefit plan costs are recognized as increases or decreases in OCI, net of income taxes. These unamortized amounts in AOCI are subsequently reclassified and recognized as amortization components of pension and OPRB costs as described above.

OPG records an offsetting regulatory asset or regulatory liability for the portion of the adjustments to AOCI that is attributable to the regulated operations in order to reflect the expected recovery or refund of these amounts through future regulated prices charged to customers. For such recoverable or refundable portion, OPG records a corresponding change in this regulatory asset or regulatory liability for the amount of the increases or decreases in OCI and for the reclassification of AOCI amounts into benefit costs during the period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Where defined benefit costs are eligible for capitalization, only the service cost component is capitalized.

v) Income Taxes and Investment Tax Credits

OPG, with the exception of certain consolidated entities, is exempt from income taxes on its operations under the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario). However, under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC), an agency of the Province. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This results in OPG paying taxes similar to those imposed under the federal and Ontario tax acts.

Certain entities consolidated by OPG are subject to income taxes under the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario). These entities are required to pay federal and provincial income taxes.

OPG's US entities are subject to US federal and state income taxes under the US Internal Revenue Code and state income tax codes. These subsidiaries file tax returns and pay taxes in the applicable jurisdictions as required under these codes.

OPG's Romanian entity is subject to Romanian tax under the Romanian Fiscal Code. This subsidiary files tax returns and pays taxes in Romania as required under this code.

OPG's operations are complex and the computation of the provision for income taxes involves interpretation of the various tax statutes and regulations. OPG has taken certain filing positions in calculating the amount of its income tax provision. These filing positions may be challenged on audit, including by the Ontario Ministry of Finance, and some of them possibly disallowed, resulting in a potential significant change in OPG's tax provision upon reassessment. A change in the tax provision upon reassessment impacting regulated operations may be recoverable from or refundable to customers through certain regulatory accounts.

OPG follows the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and deferred income tax liabilities are determined based on differences between the accounting and tax bases of assets and liabilities. Deferred amounts are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect of a change in tax rates on deferred income tax assets and deferred income tax liabilities is included in income in the period the change is enacted.

If management determines, upon considering positive and negative evidence as defined under Accounting Standards Codification Topic 740, *Income Taxes*, that it is more likely than not that some, or all, of a deferred income tax asset will not be realized, a valuation allowance is recorded to report the balance at the amount expected to be realized. The valuation allowance may be decreased in future periods if it is determined that it is more likely than not that the deferred income tax asset will be realized.

OPG recognizes deferred income taxes associated with its regulated operations and records an offsetting regulatory asset or regulatory liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return and investment tax credits are recorded only when the more likely than not recognition threshold is satisfied. Tax benefits and investment tax credits recognized are measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement.

Non-refundable investment tax credits primarily consist of Scientific Research & Experimental Development (SR&ED) tax credits, which are recorded as a reduction to income tax expense. Refundable investment tax credits are recorded as a reduction to the carrying amount of the associated asset to which they relate.

OPG classifies interest and penalties associated with unrecognized income tax benefits as income tax expense.

The income tax impact of any intra-entity transfers of non-inventory assets is recognized upon the occurrence of the transfer.

w) Changes in Accounting Estimates

Useful Lives of Nuclear Long-Lived Assets

Effective December 31, 2023, OPG revised the accounting end-of-life assumptions for Units 5 to 8 of the Pickering nuclear generating station (Pickering GS) from 2024 to 2070, reflecting the results of the updated refurbishment feasibility assessment approved by OPG's Board of Directors in August 2023 and the Province's January 2024 announcement supporting OPG to proceed with next steps toward refurbishing these units. An associated increase of $160 million was recorded to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the assets as at December 31, 2023. These changes did not impact OPG's net income in 2023 and did not have a material impact on OPG's net income in 2024, with the associated impact on expenses largely offset by OEB-authorized regulatory accounts. Further details can be found in Note 11.

x) Recent Accounting Pronouncements Not Yet Adopted

Improvements to Income Tax Disclosures

In December 2023, the Financial Accounting Standards Board (FASB) issued Accounting Standard Update (ASU) 2023-09, *Improvements to Income Tax Disclosures* (ASU 2023-09), an update to Topic 740, *Income Taxes*. The purpose of ASU 2023-09 is to enhance the transparency and decision usefulness of income tax disclosures through increasing disclosure requirements related to the rate reconciliation and income taxes paid information. The update requires specific categories to be disclosed in the rate reconciliation and additional information for reconciling items that meet a quantitative threshold. The update also requires that entities disclose income taxes paid disaggregated by federal, provincial and foreign taxes and by individual jurisdiction in which income tax paid exceeds five percent of total income taxes paid. The update is effective for annual periods beginning after December 15, 2024. Based on OPG's assessment as at December 31, 2024, this update is not expected to have a material impact on the disclosures contained in the Company's consolidated financial statements.

Disaggregation of Income Statement Expenses

In November 2024, the FASB issued ASU 2024-03, *Disaggregation of Income Statement Expenses* (ASU 2024-03), an update to Subtopic 220-40, *Income Statement – Reporting Comprehensive Income – Expense Disaggregation Disclosures*. The purpose of the standard update is to improve the disclosures about a public business entity's expenses by requiring more detailed information about the types of expenses (including purchases of inventory and employee compensation) included within consolidated income statement expense captions. The update is effective for fiscal years beginning after December 15, 2026 and interim periods beginning after December 15, 2027. Early adoption is permitted. The standard updates are to be applied prospectively with the option for retrospective application. The Company is currently evaluating the impact of adoption of the standard update on the disclosures contained within the Company's annual and interim consolidated financial statements.

y) Implementation of Accounting Standard Updates

Improvements to Reportable Segment Disclosures

In November 2023, the FASB issued ASU 2023-07, *Improvements to Reportable Segment Disclosures* (ASU 2023-07), an update to Topic 280, *Segment Reporting.* The purpose of ASU 2023-07 is to improve disclosures about a public entity's reportable segments and address requests from investors and other allocators of capital for additional, more detailed information about a reportable segment's expenses. The update is effective for fiscal years beginning after December 15, 2023 and interim periods beginning after December 15, 2024.

The revised guidance was adopted by OPG effective January 1, 2024 for all segment reporting disclosures, with 2023 comparative information conforming to the revised guidance. This update did not have a material impact on the disclosures contained in the Company's consolidated financial statements.

z) Recent Updates to Tax Laws

Following the Organization for Economic Cooperation and Development's recommendation, the Government of Canada released draft legislation in August 2023 that proposed to impose a global minimum tax of 15 percent on large multinational enterprises. The resulting *Global Minimum Tax Act* (GMTA) was enacted during the second quarter of 2024. It applies to Canadian multinational enterprises with revenue in excess of a certain threshold and is effective as of January 1, 2024, and applies to OPG. Based on preliminary estimates, the Company is not expected to have a liability with respect to the GMTA.

In March 2023, the Government of Canada announced certain refundable investment tax credits for clean energy investments. The Clean Technology Investment Tax Credit (CTITC) and the Clean Hydrogen Investment Tax Credit (CHITC) were enacted during the second quarter of 2024. The CTITC provides a 30 percent refundable tax credit and the CHITC provides a refundable tax credit ranging from 15 percent to 40 percent depending on the carbon intensity of the project, and both credits are available to federally taxable entities. If certain labour conditions are not met, these refundable credits are reduced by ten percent. OPG's federally taxable entities making eligible investments may qualify for the CTITC and the CHITC.

4. ACQUISITIONS

On January 31, 2024, through its wholly-owned subsidiary, Eagle Creek, OPG acquired Lightstar Renewables LLC and Lightstar Operations One LLC (collectively, Lightstar) for a total purchase price of $163 million (US$121 million), including cash paid of $131 million (US$97 million) and a contingent consideration of $32 million (US$24 million). Lightstar is a developer, constructor and operator of community solar assets in the US.

The acquisition was accounted for as a business combination and its results are reported within the Contracted Hydroelectric and Other Generation business segment. The fair value calculation of the major classes of assets acquired and liabilities assumed was based upon management's estimates and assumptions and determined using the exchange rate on the acquisition date. Major assets acquired consisted of $125 million of intangible assets and PP&E, with goodwill recognized of $43 million. As of December 31, 2024, the Company finalized the fair value of the assets acquired and the liabilities assumed with no adjustments to the preliminary allocations.

5. CASH, CASH EQUIVALENTS AND RESTRICTED CASH

Cash, cash equivalents and restricted cash as at December 31 were as follows:

(millions of dollars)	**2024**	**2023**
Cash and cash equivalents	**1,351**	1,459
Restricted cash	**12**	22
Total cash, cash equivalents and restricted cash	**1,363**	1,481

Restricted cash is held primarily for prescribed purposes, including debt service, insurance, general collateral purposes and other contractual arrangements.

6. PROPERTY, PLANT AND EQUIPMENT, INTANGIBLE ASSETS AND DEPRECIATION AND AMORTIZATION

PP&E as at December 31 were as follows:

(millions of dollars)	**2024**	**2023**
Nuclear generating stations	**23,888**	21,490
Regulated hydroelectric generating stations	**11,352**	11,026
Contracted hydroelectric and other generating stations	**7,696**	7,047
Atura Power generating stations	**3,562**	3,437
Other property, plant and equipment	**475**	461
Construction in progress	**4,317**	3,878
	51,290	47,339
Less: accumulated depreciation		
Generating stations	**14,911**	13,656
Other property, plant and equipment	**248**	223
	15,159	13,879
	36,131	33,460

Construction in progress as at December 31 was as follows:

(millions of dollars)	**2024**	**2023**
Darlington Refurbishment	**1,110**	1,864
Darlington New Nuclear Project	**971**	400
Pickering Refurbishment Project	**387**	15
Other	**1,849**	1,599
	4,317	3,878

Interest capitalized to construction in progress during 2024 was $136 million (2023 – $119 million), at an average rate of approximately four percent (2023 – approximately three percent).

Intangible assets as at December 31 were as follows:

(millions of dollars)	**2024**	**2023**
Nuclear generating stations	**107**	88
Regulated hydroelectric generating stations	**8**	8
Contracted hydroelectric and other generating stations [1]	**332**	165
Atura Power generating stations [1]	**126**	126
Computer software and other intangible assets	**400**	347
Development in progress	**56**	68
	1,029	802
Less: accumulated amortization		
Generating stations	**185**	110
Computer software and other intangible assets	**254**	200
	439	310
	590	492

[1] Represents power purchasing contracts, Federal Energy Regulatory Commission licences and water rights, as applicable.

Depreciation and amortization expenses, including amounts recognized in regulatory accounts, for the years ended December 31 were as follows:

(millions of dollars)	**2024**	**2023**
Depreciation	**1,281**	1,199
Amortization of intangible assets	**65**	62
Amounts recognized in regulatory variance and deferral accounts	**(161)**	(202)
Amortization of regulatory assets and regulatory liabilities *(Note 7)*	**85**	12
	1,270	1,071

7. REGULATORY ASSETS AND REGULATORY LIABILITIES

The regulatory assets and regulatory liabilities as at December 31 were as follows:

(millions of dollars)	**2024**	**2023**
Regulatory assets		
Deferral and variance accounts authorized by the OEB		
Rate Smoothing Deferral Account	**677**	654
Nuclear Liability Deferral Account	**520**	378
Capacity Refurbishment Variance Account	**460**	384
Pension & OPEB Cash Versus Accrual Differential Deferral Account	**376**	602
Hydroelectric Surplus Baseload Generation Variance Account	**307**	393
Pickering B Extension Variance Account	**131**	26
Nuclear Development Variance Account	**85**	122
Other deferral and variance accounts [1]	**174**	105
	2,730	2,664
Pension and OPEB Regulatory Asset *(Note 14)*	**-**	619
Deferred Income Taxes *(Note 12)*	**2,151**	1,938
Other	**26**	-
Total regulatory assets	**4,907**	5,221
Less: current portion	**540**	143
Non-current regulatory assets	**4,367**	5,078
Regulatory liabilities		
Deferral and variance accounts authorized by the OEB		
Pension and OPEB Cost Variance Account	**411**	319
Pension & OPEB Cash Payment Variance Account	**321**	426
Hydroelectric Water Conditions Variance Account	**173**	185
Nuclear Deferral and Variance Over/Under Recovery Variance Account	**61**	77
Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges Variance Account	**51**	32
Other deferral and variance accounts [2]	**152**	102
	1,169	1,141
Pension and OPEB Regulatory Liability *(Note 14)*	**16**	-
COVID-19 net credit to ratepayers	**-**	15
Total regulatory liabilities	**1,185**	1,156
Less: current portion	**246**	131
Non-current regulatory liabilities	**939**	1,025

[1] Represents amounts for the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, Clarington Corporate Campus Deferral Account, Fitness for Duty Deferral Account, Pickering Closure Costs Deferral Account, Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account, Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account and Impact Resulting from Changes to Pickering Station End-of-Life Dates Deferral Account (December 31, 2017).

[2] Represents amounts for the Income and Other Taxes Variance Account, SR&ED ITC Variance Account, Ancillary Services Net Revenue Variance Account, Sale of Unprescribed Kipling Site Deferral Account and Bruce Lease Net Revenues Variance Account.

During the years ended December 31, 2024 and 2023, OPG recognized regulatory assets and regulatory liabilities for additions recorded in regulatory accounts consistent with the applicable OEB decision and orders, relative to amounts reflected in the regulated prices in effect during those periods, and *Ontario Regulation 53/05*.

During the years ended December 31, 2024 and 2023, amortization of regulatory assets and liabilities for regulatory account balances and the net ratepayer credit related to impacts arising from the Company's COVID-19 pandemic response was recorded on a straight-line basis, based on the portion of the amounts authorized to be collected or repaid by the OEB's decisions and orders during the applicable period. Differences in recovery or repayment of the approved balances due to differences between forecasted electricity production used to set the deferral and variance account rate riders and actual electricity production upon which the rate riders are collected are recorded in the Nuclear Deferral and Variance Over/Under Recovery Variance Account and the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account authorized by the OEB.

Where authorized by the OEB, OPG recorded interest on unamortized balances in the regulatory accounts at an OEB-prescribed interest rate ranging from 4.40 to 5.49 percent per annum during the year ended December 31, 2024 (2023 – 4.73 to 5.49 percent per annum).

In December 2023, OPG filed an application with the OEB requesting disposition of regulatory account balances as at December 31, 2022, less amounts previously approved for recovery or repayment of the regulatory account balances as of December 31, 2019, through incremental rate riders on nuclear and regulated hydroelectric electricity generation. The application also addressed the anticipated impacts from the Market Renewal Program, an IESO initiative to redesign Ontario's electricity markets, on OPG's regulated facilities.

In June 2024, OPG and intervenors in the proceeding reached a proposed complete settlement on OPG's December 2023 application. On June 13, 2024, the OEB issued a decision and order approving the 2024 Settlement Agreement, providing for the recovery of a net total of $481 million in connection with amounts recorded in OPG's regulatory accounts and associated income tax impacts, which represented a reduction of $22 million from the amounts sought in OPG's application. This included the resolution of the parties' positions with respect to whether any of the net proceeds from OPG's sale of certain premises at 800 Kipling Avenue in Toronto, Ontario received in 2022 should be credited to ratepayers. The balances agreed by the parties are being recovered or repaid effective July 1, 2024 over a period of 30 months. The associated income tax impacts included for recovery were previously recorded as part of the regulatory asset for deferred income taxes. Based on the approved recovery or repayment periods, the OEB authorized OPG to collect $97 million in 2024 and $192 million in each of 2025 and 2026 related to these balances. The 2024 Settlement Agreement also provides for regulatory mechanisms to address the anticipated impacts from the IESO's Market Renewal Program on OPG's regulated facilities until the effective date of base regulated prices arising from OPG's next application with the OEB, as part of which any of the parties may take a different position on such mechanisms on a prospective basis. Revenue received from the recovery of regulatory account balances is largely offset by amortization expense of regulatory assets and regulatory liabilities recorded for these balances.

In the second quarter of 2024, the Company recorded a loss of $25 million in connection with the OEB's decision and order approving the 2024 Settlement Agreement.

The changes in the regulatory assets and regulatory liabilities for the years ended December 31 were as follows:

(millions of dollars)	**Rate Smoothing Deferral Account**	**Nuclear Liability Deferral Account**	**Capacity Refurbishment Variance Account**	**Pension & OPEB Cash Versus Accrual Differen-tial Deferral Account**	**Hydro-electric Surplus Baseload Genera-tion Variance Account**	**Pickering B Extension Variance Account**	**Nuclear Development Variance Account**	**Pension and OPEB Cost Variance Account**	**Pension & OPEB Cash Payment Variance Account**	**Hydro-electric Water Condi-tions Variance Account**	**Nuclear Deferral and Variance Over/Under Recovery Variance Account**	**Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges Variance Account**	**Pension and OPEB Regula-tory Asset (Liability)**	**Deferred Income Taxes**	**Other Variance and Deferral (net) Accounts**	**Other**	**Total**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)			
Net regulatory assets (liabilities) January 1, 2023	569	188	74	799	403	-	111	(78)	(460)	(172)	(75)	(14)	(1,029)	1,753	(119)	-	1,950
Increase (decrease)	64	190	259	(20)	29	26	6	(219)	(16)	(41)	(6)	-	1,648	185	15	-	2,120
Interest	21	-	13	-	17	-	6	-	(21)	(8)	(4)	(18)	-	-	1	-	7
Amortization	-	-	38	(177)	(56)	-	(1)	(22)	71	36	8	-	-	-	91	-	(12)
Net regulatory assets (liabilities) December 31, 2023	654	378	384	602	393	26	122	(319)	(426)	(185)	(77)	(32)	619	1,938	(12)	-	4,065
Increase (decrease)	**-**	**180**	**54**	**(11)**	**11**	**102**	**(18)**	**(95)**	**(12)**	**(35)**	**(1)**	**-**	**(635)**	**213**	**(51)**	**26**	**(272)**
Interest	**23**	**-**	**22**	**-**	**17**	**3**	**4**	**-**	**(18)**	**(9)**	**(4)**	**(22)**	**-**	**-**	**(2)**	**-**	**14**
Amortization	**-**	**(38)**	**-**	**(215)**	**(114)**	**-**	**(23)**	**3**	**135**	**56**	**21**	**3**	**-**	**-**	**87**	**-**	**(85)**
Net regulatory assets (liabilities) December 31, 2024	**677**	**520**	**460**	**376**	**307**	**131**	**85**	**(411)**	**(321)**	**(173)**	**(61)**	**(51)**	**(16)**	**2,151**	**22**	**26**	**3,722**

a) Rate Smoothing Deferral Account

The Rate Smoothing Deferral Account was established by the OEB's decisions and orders related to OPG's application for 2017-2021 regulated prices pursuant to *Ontario Regulation 53/05* to record, for future collection, a portion of annual OEB-approved revenue requirements for OPG's nuclear facilities during the period from January 1, 2017 to the end of the Darlington Refurbishment project. *Ontario Regulation 53/05* requires the annual deferred portion, if any, to be determined in a manner that makes more stable changes in OPG's overall production-weighted regulated price year over year. The regulation requires the OEB to determine the deferred portion on a five-year basis for the ten-year period beginning on January 1, 2017. Per the regulation, the Rate Smoothing Deferral Account records interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually. The regulation requires the OEB to authorize recovery of the balance in the account on a straight-line basis over a period not to exceed ten years following the end of the Darlington Refurbishment project.

OPG recognizes positive or negative amounts deferred under rate smoothing and recorded in the Rate Smoothing Deferral Account as an increase or decrease in the regulatory asset for the deferral account and an increase or decrease in revenue in the period to which the underlying approved revenue requirement relates, respectively.

The OEB's decisions and orders on OPG's 2022-2026 application for new regulated prices set a rate smoothing approach and the resulting nuclear base regulated prices such that no portion of the nuclear revenue requirement is to be deferred from 2024 to 2026.

b) Nuclear Liability Deferral Account

Pursuant to *Ontario Regulation 53/05*, the OEB has authorized the Nuclear Liability Deferral Account in connection with changes to OPG's liabilities for used nuclear fuel management and nuclear decommissioning and L&ILW management associated with the Darlington and Pickering nuclear generating stations. The deferral account records the revenue requirement impact associated with changes in these liabilities arising from an approved reference plan, in accordance with the terms of the ONFA.

Effective January 1, 2022, the Province approved an updated reference plan under the ONFA, for the years 2022 to 2026 (2022 ONFA Reference Plan). As the nuclear base regulated prices in effect during the 2022-2026 period do not reflect the impact of the 2022 ONFA Reference Plan, effective January 1, 2022, OPG records an incremental regulatory asset for the Nuclear Liability Deferral Account representing the revenue requirement impact for the Darlington and Pickering nuclear generating stations arising from the approved 2022 ONFA Reference Plan. OPG will continue to record such additions to the Nuclear Liability Deferral Account until impacts arising from the approved 2022 ONFA Reference Plan are reflected in nuclear base regulated prices in the future.

Components of the regulated asset recorded for the Nuclear Liability Deferral Account during the years ended December 31, with reductions to corresponding expenses, are summarized as follows:

(millions of dollars)	**2024**	**2023**
Fuel expense	**21**	20
Low and intermediate level waste management variable expenses [1]	**26**	31
Depreciation expense	**110**	110
Return on rate base [2]	**3**	7
Income taxes	**20**	22
	180	190

[1] Amount was recorded as a reduction to OM&A expenses.
[2] Amount was recorded as a reduction to accretion on fixed asset removal and nuclear waste management liabilities.

c) Capacity Refurbishment Variance Account

Pursuant to *Ontario Regulation 53/05*, the OEB has authorized the Capacity Refurbishment Variance Account to record revenue requirement variances from forecasts reflected in OPG's regulated prices approved by the OEB for capital and non-capital costs and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to one or more of OPG's regulated generating facilities, including costs related to the refurbishment of the Darlington nuclear generating station (Darlington GS), life extension initiatives at the Pickering GS, refurbishment and other life extension activities at regulated hydroelectric facilities, and other eligible projects.

d) Pension & OPEB Cash Versus Accrual Differential Deferral Account

The Pension & OPEB Cash Versus Accrual Differential Deferral Account was originally established by the OEB's November 2014 decision and December 2014 order and was continued by the OEB's decisions and orders related to OPG's application for 2017-2021 regulated prices. For the period from November 1, 2014 to December 31, 2021, this deferral account recorded, for the regulated hydroelectric facilities and the nuclear facilities, the differences between OPG's actual pension and OPEB costs determined on the accrual basis of accounting under US GAAP and OPG's corresponding actual cash expenditures for these plans.

The account continues to record the above difference for the regulated hydroelectric facilities. The approved nuclear base regulated prices for the 2022-2026 period reflect recovery of pension and OPEB costs calculated on the accrual basis of accounting. Therefore, for the nuclear facilities, the account only records amortization of balances approved for recovery by the OEB effective January 1, 2022. As discussed in Note 3, the Company has recognized the amount set aside in the deferral account as a regulatory asset.

In accordance with US GAAP requirements, OPG recognizes a regulatory asset for the OPRB portion of deferred costs recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account to the extent that the recovery of these costs commences within five years and is completed in full within 20 years of the period in which the costs were incurred, provided that the pattern of recovery within these constraints does not result in rate increases for a future year that is higher than the previous year. Taking into account the recovery of balances in the Pension & OPEB Cash Versus Accrual Differential Deferral Account approved by the OEB, OPG continues to satisfy the above requirements for continued recognition of the regulatory asset for the OPRB portion of deferred costs.

e) Hydroelectric Surplus Baseload Generation Variance Account

The Hydroelectric Surplus Baseload Generation Variance Account records the impact of forgone production at OPG's regulated hydroelectric facilities due to surplus baseload generation conditions.

f) Pickering B Extension Variance Account

The Pickering B Extension Variance Account was established pursuant to an amendment to *Ontario Regulation 53/05* made in December 2022. The variance account records the difference between the revenues generated from the output of Units 5 to 8 at the Pickering GS during the period from January 1, 2026 to September 30, 2026, and the sum of any forgone revenue related to forgone output from these units arising from activities undertaken in furtherance of their operation during the period from January 1, 2026 to September 30, 2026 and the revenue requirement impact resulting from actual capital and non-capital costs incurred for such extension activities.

On January 28, 2025, the Province released a proposal for potential amendments to *Ontario Regulation 53/05* intended clarify the scope of the Pickering B Extension Variance Account to ensure that OPG can record costs incurred beginning in 2024 to retain the capacity and readiness to operate Units 5 to 8 of the Pickering GS upon refurbishment, subject to the requisite approvals. The comment period for the proposal ends on March 14, 2025.

g) Nuclear Development Variance Account

Pursuant to *Ontario Regulation 53/05*, the Nuclear Development Variance Account records variances between the revenue requirement impact of actual capital and non-capital costs incurred and firm financial commitments made for proposed new nuclear generation facilities and the corresponding forecasts reflected in OPG's regulated prices approved by the OEB. In its November 2021 decision on OPG's 2022-2026 application for new regulated prices, the OEB determined that OPG's non-capital costs related to the development of a small modular reactor (SMR) at the Darlington New Nuclear Project (DNNP) site were being appropriately recorded in the Nuclear Development Variance Account and, in its June 2024 decision approving the 2024 Settlement Agreement, authorized the recovery of such balance as at December 31, 2022.

h) Pension and OPEB Cost Variance Account

The Pension and OPEB Cost Variance Account was established to record, for the regulated hydroelectric facilities and the nuclear facilities, the differences between OPG's actual pension and OPEB costs determined on the accrual basis of accounting and related tax impacts and corresponding forecast amounts reflected in the regulated prices then in effect. Based on the OEB's November 2014 and other subsequent decisions, the account recorded only amortization for the period from November 1, 2014 to December 31, 2021, as applicable. As the approved nuclear base regulated prices for the 2022-2026 period reflect recovery of pension and OPEB costs calculated on the accrual basis of accounting, the account has resumed recording the above difference for the nuclear facilities effective January 1, 2022, as approved by the OEB.

i) Pension & OPEB Cash Payment Variance Account

The Pension & OPEB Cash Payment Variance Account records the differences between OPG's actual contributions to its registered pension plan and expenditures on its OPEB and supplementary pension plans for the regulated hydroelectric facilities, and such forecast amounts reflected in the regulated prices. The approved nuclear base regulated prices for the 2022-2026 period reflect recovery of pension and OPEB costs calculated on the accrual basis of accounting. Therefore, for the nuclear facilities, the account only records amortization of balances approved for recovery by the OEB effective January 1, 2022.

j) Hydroelectric Water Conditions Variance Account

The Hydroelectric Water Conditions Variance Account records the impact of differences in regulated hydroelectric electricity production due to differences between forecast water conditions underlying the production forecast approved by the OEB in setting regulated hydroelectric prices, and the actual water conditions.

k) Nuclear Deferral and Variance Over/Under Recovery Variance Account

The Nuclear Deferral and Variance Over/Under Recovery Variance Account records differences in recovery of the approved balances in the regulatory accounts related to the nuclear facilities due to differences between forecasted electricity production from the nuclear facilities used to set rate riders for recovery or repayment of these balances and the actual electricity production from the nuclear facilities upon which the rate riders are collected.

l) Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges Variance Account

The Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges Variance Account records asymmetric carrying charges in favour of customers on differences between pension and OPEB costs determined on the accrual basis that are recovered in regulated prices, including amounts recovered from the Pension & OPEB Cash Versus Accrual Differential Deferral Account, and the cash payments made in respect of pension and OPEB plans in connection with the regulated facilities.

m) Pension and OPEB Regulatory Asset and Regulatory Asset (Liability)

The Pension and OPEB Regulatory Asset and the Pension and OPEB Regulatory Liability represent unamortized amounts in respect of OPG's pension and OPEB plans that have been recognized in OCI and not yet reclassified into the amortization component of the benefit costs in respect of these plans. These amounts are expected to be settled with customers through future regulated prices. The regulatory asset or regulatory liability is reduced as underlying unamortized balances are amortized as components of benefit costs. For further details, refer to Note 3 under the heading, *Rate Regulated Accounting*. The AOCI amounts related to pension and OPEB plans are presented in Note 13.

n) Deferred Income Taxes

In accordance with US GAAP, OPG is required to record a regulatory asset or regulatory liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers for generation from OPG's regulated facilities. In addition, OPG is required to recognize a deferred income tax liability or deferred income tax asset for the regulatory asset or regulatory liability for the amount of deferred income taxes expected to be included in future regulated prices and recovered from, or paid to customers. Income taxes are discussed in Note 12.

8. GOODWILL

All goodwill pertains to the Contracted Hydroelectric and Other Generation business segment. The goodwill recorded as at December 31 was as follows:

(millions of dollars)	**2024**	**2023**
Opening balance, January 1	**168**	172
Acquisition of Lightstar *(Note 4)*	**43**	-
Foreign exchange differences	**19**	(4)
Closing balance, December 31	**230**	168

An annual goodwill impairment assessment is performed as of the same date each year. In the fourth quarter of 2024, as per the Company's policy, the assessment was performed and no impairment factors were identified. The Company concluded that the fair value of the Contracted Hydroelectric and Other Generation business segment exceeded its carrying value as of the assessment date.

9. LONG-TERM DEBT AND NET INTEREST EXPENSE

Long-term debt as at December 31 was as follows:

(millions of dollars)	Weighted Average Interest Rate	Maturity	2024	2023
Medium Term Note Program [1]				
Senior Notes	3.63%	2025 - 2054	**5,950**	4,650
Notes payable under OEFC and corporate credit facilities [1]				
Senior Notes	3.44%	2026 - 2048	**2,859**	2,822
UMH Energy Partnership [2]				
Senior Notes	7.59%	2041	**160**	163
PSS Generating Station Limited Partnership [3]				
Senior Notes	4.80%	2067	**245**	245
Lower Mattagami Energy Limited Partnership [4]				
Senior Notes	3.98%	2026 - 2054	**1,995**	1,995
OPG Eagle Creek Holdings LLC and subsidiaries [5]				
Senior Notes	4.84%	2025 - 2030	**516**	474
Other			**25**	25
			11,750	10,374
Plus: net fair value premium			**-**	5
Less: unamortized bond issuance fees			**(43)**	(37)
Less: amounts due within one year			**(604)**	(603)
Long-term debt			**11,103**	9,739

[1] These notes are direct unsecured obligations of OPG and rank *pari passu* with all of OPG's unsubordinated and unsecured obligations.
[2] These notes are secured by the assets of the Upper Mattagami and Hound Chute project. Principal repayments of approximately $3 million per year are made on a semi-annual basis until maturity in 2041, at which time the remaining principal balance of $116 million becomes due.
[3] These notes are secured by the assets of the Peter Sutherland Sr. GS project, and are recourse to OPG until the recourse release date. These notes rank *pari passu* with all of OPG's unsubordinated and unsecured obligations. The notes have an interest-only feature until 2025 and will be amortized with blended semi-annual principal and interest payments thereafter until maturity in 2067, at which time the remaining principal balance of $49 million becomes due.
[4] These notes are secured by the assets of the Lower Mattagami River project, including existing and new operating facilities.
[5] These notes are secured by the corresponding assets of the respective subsidiary.

For the year ended December 31, 2024, net issuance of long-term debt under the Company's corporate credit facilities totalled $37 million (2023 – net issuance of $204 million), which comprised issuances of $437 million (2023 – issuances of $244 million) repayment of $400 million (2023 – repayment of $40 million).

On June 7, 2024, OPG's wholly-owned Lower Mattagami Energy Limited Partnership (LME) completed a private placement bond offering with the issuance of $200 million of green bonds, maturing in June 2054, with a coupon interest rate of 4.69 percent. The net proceeds were used to refinance LME debt maturities in June 2024.

On June 28, 2024, OPG issued $1 billion of green bonds under its Sustainable Finance Framework, through its Medium Term Note Program. The issuance consisted of $500 million senior notes maturing in June 2034, with a coupon interest rate of 4.83 percent, and $500 million senior notes maturing in June 2054, with a coupon interest rate of 4.99 percent.

On September 11, 2024, OPG re-opened the June 28, 2024 dual tranche bond issuances under its Medium Term Note Program for an additional $300 million. The additional green bond issuance consisted of $200 million of senior notes maturing in June 2034, with a coupon interest rate of 4.83 percent, and $100 million of senior notes maturing in June 2054, with a coupon interest rate of 4.99 percent.

Net Interest Expense

Net interest expense for the years ended December 31 was as follows:

(millions of dollars)	2024	2023
Interest on long-term debt	**401**	373
Interest on short-term debt	**24**	15
Interest income	**(88)**	(101)
Interest capitalized to property, plant and equipment and intangible assets	**(136)**	(119)
Interest related to regulatory assets and regulatory liabilities [1]	**(15)**	(65)
Net interest expense	**186**	103

[1] Includes interest to recognize the cost of financing regulatory account balances as authorized by the OEB, and interest costs deferred in certain regulatory accounts.

Interest paid in 2024 was $442 million (2023 – $395 million), of which $418 million (2023 – $380 million) relates to interest paid on long-term debt.

The total net book value of the pledged assets of PSS Generating Station Limited Partnership (PSS), UMH Energy Partnership (UMH), LME, Lower Mattagami Limited Partnership (LMLP) and Eagle Creek and its subsidiaries against their debt as at December 31, 2024 was $5,013 million (2023 – $4,941 million).

10. SHORT-TERM DEBT

Committed credit facilities and maturity dates as at December 31, 2024 were as follows:

(millions of dollars)		Amount	Maturity
Bank facilities:			
Corporate		**1,211**	July 2025 and May 2029 [1]
Corporate	US Dollars	**750**	November 2025 [2]
Lower Mattagami Energy Limited Partnership		**460**	June 2029 [3]
OPG Eagle Creek Holdings LLC and subsidiaries	US Dollars	**20**	October 2028
Ontario Financing Authority facility		**1,250**	December 2029 [1]
Ontario Electricity Financial Corporation facility		**750**	December 2026 [1]

[1] Represents amounts available under the facility net of debt issuances. Of the total available corporate credit facilities, $211 million matures by September 2027 and is available to finance certain expenditures of the DNNP, subject to certain conditions, and $1,000 million matures in May 2029.
[2] The facility has a one-year extension option beyond the maturity date of November 2025.
[3] A letter of credit of $60 million was outstanding under this facility as at December 31, 2024.

Short-term debt as at December 31 was as follows:

(millions of dollars)	2024	2023
Lower Mattagami Energy Limited Partnership	**215**	200
Total short-term debt	**215**	200

As of December 31, 2024, a total of $504 million of letters of credit had been issued (2023 – $525 million). As of December 31, 2024, this included $314 million for the supplementary pension plans, $60 million for LME, $51 million for general corporate purposes, $45 million for Atura Power, $19 million for Eagle Creek and its subsidiaries, $14 million for UMH, and $1 million for PSS.

For the year ended December 31, 2024, net issuance of short-term debt totalled $15 million (2023 – net issuance of $135 million), which was comprised of issuances of $2,960 million (2023 – $970 million) and repayments of $2,945 million (2023 – $835 million).

The weighted average interest rate on the short-term debt as of December 31, 2024 is 3.71 percent (2023 – 5.29 percent).

11. NUCLEAR FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT FUNDS AND FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

Liabilities for fixed asset removal and nuclear waste management on a present value basis as at December 31 were as follows:

(millions of dollars)	**2024**	**2023**
Liability for used nuclear fuel management	**15,991**	15,623
Liability for nuclear decommissioning and nuclear low and intermediate level waste management	**9,782**	9,493
Liability for non-nuclear fixed asset removal	**269**	270
Fixed asset removal and nuclear waste management liabilities	**26,042**	25,386

The changes in the fixed asset removal and nuclear waste management liabilities for the years ended December 31 were as follows:

(millions of dollars)	**2024**	**2023**
Liabilities, beginning of year	**25,386**	24,315
Increase in liabilities due to accretion [1]	**1,203**	1,162
Increase in liabilities reflecting changes to the estimated useful lives of nuclear generating stations *(Note 3)*	**-**	160
Decrease in liabilities reflecting changes in the estimate of liabilities for thermal generating facilities and other adjustments	**(10)**	(10)
Increase in liabilities due to used nuclear fuel, nuclear waste management and other expenses [1]	**163**	195
Liabilities settled by expenditures on fixed asset removal and nuclear waste management during the year [2]	**(700)**	(436)
Liabilities, end of year	**26,042**	25,386

[1] Amounts shown exclude the impact of regulatory accounts.
[2] Includes accruals for expenditures eligible for reimbursement from the Nuclear Segregated Funds.

OPG's fixed asset removal and nuclear waste management liabilities are comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear, thermal and solar generating facilities, and other facilities. Costs will be incurred for activities such as preparation for safe storage and safe storage of nuclear generating stations, dismantlement, demolition and disposal of facilities and equipment, remediation and restoration of sites, and the ongoing and long-term management of used nuclear fuel and L&ILW material.

The determination of the accrual for fixed asset removal and nuclear waste management costs requires significant assumptions since these programs are long-term in nature. The most recent comprehensive update of the cost estimates for the Nuclear Liabilities is contained in the 2022 ONFA Reference Plan approved by the Province in accordance with ONFA. This update has been reflected in the Nuclear Liabilities since December 31, 2021. As of December 31, 2023, OPG recorded an increase of $160 million in the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of nuclear PP&E to reflect the extension of the accounting

end-of-life assumptions for Units 5 to 8 of the Pickering GS, as discussed in Note 3. The increase in the liabilities as at December 31, 2023 was determined by discounting the net incremental future cash flows at 3.93 percent.

For the purposes of calculating the Nuclear Liabilities as at December 31, 2024, consistent with the current accounting end-of-life assumptions for the nuclear generating stations, nuclear facilities decommissioning activities are projected to occur over approximately the next 80 years and the placement of used nuclear fuel into the assumed long-term deep geological repository (DGR) under the APM is projected to occur until 2106, followed by extended monitoring.

A number of significant assumptions used in the calculation of the accrued liabilities are subject to inherent uncertainty and judgment. The significant assumptions underlying operational, technical and economic factors used in the calculation of the Nuclear Liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the programs, construction of assumed disposal facilities, station end-of-life dates, disposal methods, financial indicators, decommissioning strategy and the technology employed, may result in significant changes to the value of the accrued liabilities. With programs of such long-term duration and the evolving technology to handle nuclear waste, there is a significant degree of inherent uncertainty surrounding the measurement of the costs for these programs, including from factors beyond the Company's control. These costs may increase or decrease materially over time.

Liability for Used Nuclear Fuel Management Costs

The liability for used nuclear fuel management represents the cost of managing the used nuclear fuel bundles. The federal NFWA, proclaimed into force in 2002, required that Canada's used nuclear fuel owners form a nuclear waste management organization, and that each such owner establish a trust fund for used nuclear fuel management costs as specified in the NFWA. This organization, the NWMO, is responsible for the design and implementation of Canada's plan for the long-term management of used nuclear fuel. To estimate its liability for used nuclear fuel management costs, OPG has adopted an approach consistent with the APM concept approved by the Government of Canada. On November 28, 2024, the NWMO announced that it had selected Wabigoon Lake Ojibway Nation and the Township of Ignace, Ontario as the host communities for the future site of Canada's DGR for used nuclear fuel under the APM.

Liability for Nuclear Decommissioning and L&ILW Management Costs

The liability for nuclear decommissioning and L&ILW management represents the estimated costs of decommissioning the nuclear generating stations after the end of their service lives, as well as the cost of managing L&ILW generated by the stations.

The significant assumptions used in estimating future nuclear fixed asset removal costs include a deferred dismantlement basis for decommissioning of the nuclear generating stations. Under this strategy, each reactor will be defueled and de-watered immediately after it has ceased operation and prepared for a period of safe storage and monitoring. Station dismantlement and site restoration activities will take place over a period of time after an appropriate safe storage period. The life cycle costs of L&ILW management include the costs of processing and storage of such materials during and following the operation of the nuclear generating stations, as well as the costs of the ultimate long-term management of these materials. The assumptions used to establish the obligation for these costs recognized in the consolidated financial statements include a conceptual long-term disposal strategy assumption consistent with the NWMO's recommended integrated strategy for the long-term management of irradiated wastes in Canada, as set out in its Integrated Strategy for Radioactive Waste (ISRW) prepared at the request of the Government of Canada and subsequently accepted by the federal Minister of Energy and Natural Resources in 2023. The strategy contemplates disposal of low-level waste in near-surface disposal facilities to be implemented by the waste owners and disposal of intermediate-level waste and the small amount of non-fuel high-level waste in a central DGR to be implemented by the NWMO. OPG will continue to evaluate underlying assumptions and estimates based on available information, including developments related to the NWMO's future siting process for such DGR.

Liability for Non-Nuclear Fixed Asset Removal Costs

The liability for non-nuclear fixed asset removal primarily represents the estimated costs of decommissioning OPG's thermal generating stations at the end of their service lives. The liability is based on third-party cost estimates following a review of plant sites and an assessment of required clean-up and restoration activities. For the purposes of measuring the non-nuclear fixed asset removal liability, thermal asset removal activities are assumed to take place over approximately the next 40 years.

Ontario Nuclear Funds Agreement

In accordance with the ONFA, OPG sets aside and invests funds that are held in segregated custodian and trustee accounts specifically for discharging its life cycle obligation for nuclear decommissioning and long-term nuclear waste management in connection with the existing facilities. The Used Fuel Segregated Fund and the Decommissioning Segregated Fund were established under the ONFA for this purpose. OPG makes contributions, if any, to the Nuclear Segregated Funds based on the approved ONFA reference plan in effect. ONFA reference plans and associated contribution schedules are subject to approval by the Province. The Ontario NFWA Trust (NFWA Trust) established by OPG pursuant to the NFWA forms part of the Used Segregated Fund, with any portion of the fund not in the NFWA Trust being able to be applied towards the NFWA Trust's annual contribution requirements pursuant to the NFWA.

As required under the ONFA reference plans in effect, OPG has made contributions to the Used Fuel Segregated Fund based on the assumed lives of its nuclear generating stations, as specified in the ONFA. ONFA requirements have resulted in the majority of the underlying used nuclear fuel obligation being funded through OPG contributions over the initial estimated useful lives of the nuclear generating stations assumed in the ONFA, which did not reflect subsequent refurbishment and other life extension decisions for the stations.

To date, OPG has not been required to make contributions to the Decommissioning Segregated Fund, which was fully funded at its inception through the initial contribution made by the OEFC and, taking into account fund asset performance and changes in underlying funding obligations over time, at the time of every subsequent approved ONFA reference plan.

Based on the funded status of the Used Fuel Segregated Fund and the Decommissioning Segregated Fund reflecting the life cycle liability estimates per the 2022 ONFA Reference Plan, no overall contributions to either fund are currently required. Contributions may be required in the future should either or both of the funds be in an underfunded position when a new or amended ONFA reference plan is prepared.

The *Nuclear Safety and Control Act* (Canada) requires OPG to have sufficient funds available to discharge its existing nuclear waste management and nuclear facilities decommissioning obligations. The CNSC process requires the CNSC financial guarantee requirement to be updated once every five years and for OPG to provide an annual report to the CNSC on the assumptions, fund asset values and resulting financial guarantee requirements. The CNSC financial guarantee requirement calculation takes into account used nuclear fuel and L&ILW expected to be generated to the end of each year. In 2022, the CNSC accepted OPG's proposed CNSC financial guarantee requirement for the 2023-2027 period to be satisfied by the forecast fair market value of the Nuclear Segregated Funds without the requirement for a Provincial guarantee. As provided by the terms of the ONFA, the Province is committed to provide a Provincial guarantee to the CNSC as required, on behalf of OPG, should there be a shortfall between the CNSC financial guarantee requirement and the fair market value of the Nuclear Segregated Funds during the 2023-2027 period, as it has done in the past. OPG pays the Province an annual guarantee fee equal to 0.5 percent of the outstanding amount, if any, of the Provincial guarantee.

Investments in the Nuclear Segregated Funds include a diversified portfolio of equity and fixed income securities, pooled funds, infrastructure, real estate and other investments. As the Nuclear Segregated Funds are invested to fund long-term liability requirements, the portfolio asset mix is structured to achieve the required return over a long-term horizon. While short-term fluctuations in the market value will occur, managing the long-term return of the Nuclear

Segregated Funds remains the primary goal. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

Decommissioning Segregated Fund

Under the ONFA, OPG is wholly responsible for cost estimate changes and investment returns in the Decommissioning Segregated Fund.

Upon termination of the ONFA, the Province has the sole right to any excess funds in the Decommissioning Segregated Fund, which is the excess of the fair market value of the fund's assets over the underlying estimated future costs, as per the most recently approved ONFA reference plan. Accordingly, when the Decommissioning Segregated Fund is overfunded, OPG limits the fund earnings recognized in the consolidated financial statements by recording an amount due to the Province, such that the fund asset recognized on the consolidated balance sheets is equal to the cost estimate of the funding liability based on the most recently approved ONFA reference plan. Additionally, OPG recognizes the portion of the surplus that it may direct to the Used Fuel Segregated Fund, which is possible when the surplus in the Decommissioning Segregated Fund is such that the underlying liabilities, as defined by the most recently approved ONFA reference plan, are at least 120 percent funded. In those circumstances, OPG may direct, at the time a new or amended reference plan is approved, up to 50 percent of the surplus over 120 percent to the Used Fuel Segregated Fund, with the OEFC being entitled to a distribution of an equal amount. Therefore, when the Decommissioning Segregated Fund is at least 120 percent funded, OPG recognizes 50 percent of the excess greater than 120 percent in income, up to the amount by which the Used Fuel Segregated Fund is underfunded.

When the Decommissioning Segregated Fund is in an overfunded status of less than 120 percent, the above results in OPG recognizing annual earnings on the fund at 3.25 percent plus the long-term Ontario Consumer Price Index (CPI) specified in the most recently approved ONFA reference plan, which is the rate of growth in the underlying funding liability. The same treatment is applied when the Decommissioning Segregated Fund is in an overfunded status of greater than 120 percent, if the Used Fuel Segregated Fund is fully funded. When the Decommissioning Segregated Fund is underfunded, the earnings on the fund reflect actual fund returns based on the market value of the assets.

As at December 31, 2024 and 2023, the Decommissioning Segregated Fund was in an overfunded position of greater than 120 percent based on the approved ONFA reference plan in effect. As a result, OPG recognized a due to the Province amount such that the Decommissioning Segregated Fund asset on the consolidated balance sheets as at December 31, 2024 and 2023 was limited to the value of the underlying funding liability per the approved ONFA reference plan in effect, plus 50 percent of the surplus over 120 percent up to the amount, if any, by which the Used Fuel Segregated Fund was underfunded. This payable to the Province may be reduced in subsequent periods in the event that the Decommissioning Segregated Fund earns less than its target rate of return, a new or amended ONFA reference plan is approved with a higher underlying funding liability, or the amount of the underfunding, if any, in the Used Fuel Segregated Fund increases.

Used Fuel Segregated Fund

OPG is responsible for cost increases in the funding liability for used nuclear fuel management under the ONFA, subject to specified graduated liability thresholds, pursuant to which the Province limits OPG's total financial exposure for the first 2.23 million used nuclear fuel bundles at approximately $24.1 billion in present value dollars as at December 31, 2024. The graduated liability thresholds do not apply to used nuclear fuel bundles beyond the 2.23 million threshold.

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Segregated Fund at 3.25 percent plus the change in the Ontario CPI, as defined by ONFA, for funding related to the first 2.23 million used nuclear fuel bundles, (committed return). OPG recognizes the committed return on the Used Fuel Segregated Fund as earnings on the Nuclear Segregated Funds. The difference between the committed return and the actual market return determined based on the fair value of the fund assets related to the first 2.23 million used nuclear fuel bundles is recorded as due to or due from the Province. This amount due to or due from the Province represents the amount that would be paid to

or received from the Province if the committed return were to be settled as at the consolidated balance sheet date. Upon approval of a new or amended ONFA reference plan, the Province is obligated to make an additional contribution to the Used Fuel Segregated Fund in relation to the first 2.23 million used nuclear fuel bundles if the fund assets earned a rate of return that is less than the guaranteed rate of return. If the return on the fund assets exceeded the Province's guaranteed rate of return, the Province is entitled to withdraw any portion of such excess related to the first 2.23 million used nuclear fuel bundles, upon approval of a new or amended ONFA reference plan. The 2.23 million threshold represents the estimated total life cycle used nuclear fuel bundles based on the initial estimated useful lives of the nuclear generating stations assumed in the ONFA.

As prescribed under the ONFA, OPG's contributions for used nuclear fuel bundles in excess of 2.23 million are not subject to the rate of return guaranteed by the Province, and earn a return based on changes in the market value of the assets of the Used Fuel Segregated Fund.

If there is a surplus in the Used Fuel Segregated Fund such that the underlying liabilities, as defined by the most recently approved ONFA reference plan, are at least 110 percent funded after taking into account the committed return adjustment, the Province, has the right, at any time, to access the excess amount greater than 110 percent. Upon termination of the ONFA, the Province has the sole right to any surplus in the fund, which is the excess of the fair market value of the Used Fuel Segregated Fund assets over the estimated future costs, as per the most recently approved ONFA reference plan. Neither OPG nor the Province have a right to direct any amounts from the Used Fuel Segregated Fund to the Decommissioning Segregated Fund. Therefore, when the Used Fuel Segregated Fund is overfunded after taking into account the committed return adjustment, OPG limits the earnings it recognizes on the fund by recording an amount due to the Province, such that the fund asset recognized on the consolidated balance sheets is equal to the cost estimate of the funding liability based on the most recently approved ONFA reference plan. When the fund is overfunded, this results in OPG recognizing annual earnings on the fund, after taking into account the committed return adjustment, at 3.25 percent plus the long-term Ontario CPI specified in the most recently approved ONFA reference plan, which is the rate of growth in the underlying funding liability.

Based on the approved ONFA reference plan in effect, the Used Fuel Segregated Fund was in an overfunded position as at December 31, 2024 and 2023, after taking into account the committed return adjustment. The due to the Province amount recognized for the fund as at December 31, 2024 and 2023 related to the committed return adjustment and the overfunded position of the fund.

Nuclear Segregated Funds

The nuclear fixed asset removal and nuclear waste management funds as at December 31 were as follows:

(millions of dollars)	Fair Value 2024	2023
Decommissioning Segregated Fund	**14,220**	12,713
Due to Province – Decommissioning Segregated Fund	**(4,545)**	(3,408)
	9,675	9,305
Used Fuel Segregated Fund [1]	**18,428**	16,490
Due to Province – Used Fuel Segregated Fund	**(5,691)**	(4,232)
	12,737	12,258
Total Nuclear Segregated Funds	**22,412**	21,563
Less: current portion	**(283)**	(68)
Non-current Nuclear Segregated Funds	**22,129**	21,495

[1] The NFWA Trust represents $5,211 million as at December 31, 2024 (2023 – $4,867 million) of the Used Fuel Segregated Fund on a fair value basis.

The fair values of the securities invested in the Nuclear Segregated Funds as at December 31 were as follows:

	Fair Value	
(millions of dollars)	**2024**	**2023**
Cash and cash equivalents and short-term investments	**444**	224
Alternative investments	**8,424**	7,618
Pooled funds	**3,447**	3,209
Marketable equity securities	**11,926**	10,614
Fixed income securities	**8,352**	7,475
Net receivables/payables	**55**	63
	32,648	29,203
Less: Due to Province	**(10,236)**	(7,640)
	22,412	21,563

The historical cost, gross unrealized aggregate appreciation and gross unrealized depreciation of investments, gross unrealized foreign exchange gains and fair value of the Nuclear Segregated Funds as at December 31 were as follows:

	2024		
(millions of dollars)	**Decommissioning Segregated Fund**	**Used Fuel Segregated Fund**	**Total**
Historical cost	**11,392**	**14,828**	**26,220**
Gross unrealized gains (losses)			
Aggregate appreciation	**2,733**	**3,450**	**6,183**
Aggregate depreciation	**(522)**	**(638)**	**(1,160)**
Foreign exchange	**617**	**788**	**1,405**
	14,220	**18,428**	**32,648**
Less: Due to Province	**(4,545)**	**(5,691)**	**(10,236)**
Total fair value	**9,675**	**12,737**	**22,412**
Less: current portion	**(60)**	**(223)**	**(283)**
Non-current fair value	**9,615**	**12,514**	**22,129**

	2023		
(millions of dollars)	**Decommissioning Segregated Fund**	**Used Fuel Segregated Fund**	**Total**
Historical cost	10,424	13,619	24,043
Gross unrealized gains (losses)			
Aggregate appreciation	2,565	3,201	5,766
Aggregate depreciation	(496)	(597)	(1,093)
Foreign exchange	220	267	487
	12,713	16,490	29,203
Less: Due to Province	(3,408)	(4,232)	(7,640)
Total fair value	9,305	12,258	21,563
Less: current portion	(24)	(44)	(68)
Non-current fair value	9,281	12,214	21,495

Net realized and unrealized gains or losses from investments in the Nuclear Segregated Funds for the years ended December 31 were as follows:

(millions of dollars)	2024 Decommissioning Segregated Fund	2024 Used Fuel Segregated Fund	2024 Total
Net realized gains			
Net realized gains excluding foreign exchange	**759**	**950**	**1,709**
Net realized foreign exchange gains	**58**	**72**	**130**
Net realized gains	**817**	**1,022**	**1,839**
Net unrealized gains			
Net unrealized gains excluding foreign exchange	**34**	**203**	**237**
Net unrealized foreign exchange gains	**505**	**526**	**1,031**
Net unrealized gains	**539**	**729**	**1,268**

(millions of dollars)	2023 Decommissioning Segregated Fund	2023 Used Fuel Segregated Fund	2023 Total
Net realized gains			
Net realized gains excluding foreign exchange	328	421	749
Net realized foreign exchange gains	68	107	175
Net realized gains	396	528	924
Net unrealized gains			
Net unrealized gains excluding foreign exchange	671	858	1,529
Net unrealized foreign exchange losses	(198)	(276)	(474)
Net unrealized gains	473	582	1,055

The change in the Nuclear Segregated Funds for the years ended December 31 were as follows:

(millions of dollars)	Fair Value 2024	Fair Value 2023
Decommissioning Segregated Fund, beginning of year	**9,305**	8,919
Increase in fund due to return on investments	**1,612**	1,102
Decrease in fund due to reimbursement of eligible expenditures	**(105)**	(70)
Increase in due to Province	**(1,137)**	(646)
Decommissioning Segregated Fund, end of year	**9,675**	9,305
Used Fuel Segregated Fund, beginning of year	**12,258**	11,787
Increase in fund due to return on investments	**2,085**	1,419
Decrease in fund due to reimbursement of eligible expenditures	**(147)**	(128)
Increase in due to Province	**(1,459)**	(820)
Used Fuel Segregated Fund, end of year	**12,737**	12,258

The earnings from the Nuclear Segregated Funds during the years ended December 31, 2024 and 2023 were impacted by the Bruce Lease Net Revenues Variance Account authorized by the OEB. The earnings on the Nuclear Segregated Funds for the years ended December 31 were as follows:

(millions of dollars)	**2024**	**2023**
Decommissioning Segregated Fund	**475**	456
Used Fuel Segregated Fund	**626**	599
Bruce Lease Net Revenues Variance Account	**1**	2
Earnings on nuclear fixed asset removal and nuclear waste management funds	**1,102**	1,057

12. INCOME TAXES

OPG follows the liability method of accounting for income taxes. The Company records an offsetting regulatory asset or regulatory liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers for electricity generation from OPG's regulated facilities.

A reconciliation between the statutory and the effective rate of income taxes for the years ended December 31 was as follows:

(millions of dollars)	**2024**	**2023**
Income before income taxes	**1,176**	2,095
Combined Canadian federal and provincial statutory enacted income tax rates	**26.5%**	26.5%
Statutory income tax rates applied to accounting income	**312**	555
(Decrease) increase in income taxes resulting from:		
Income tax expense deferred in regulatory assets and regulatory liabilities	**(125)**	(161)
Scientific Research and Experimental Development investment tax credits	**(22)**	(25)
Manufacturing and processing credit	**(18)**	(31)
Valuation allowance	**15**	(1)
Other	**8**	(1)
	(142)	(219)
Income tax expense	**170**	336
Effective rate of income taxes	**14.5%**	16.0%

Significant components of the income tax expense for the years ended December 31 were as follows:

(millions of dollars)	**2024**	**2023**
Current income tax expense	**131**	254
Deferred income tax expense	**39**	82
Income tax expense	**170**	336

The income tax effects of temporary differences that give rise to deferred income tax assets and deferred income tax liabilities as at December 31 were as follows:

(millions of dollars)	**2024**	**2023**
Deferred income tax assets:		
Fixed asset removal and nuclear waste management liabilities	**6,512**	6,325
Other assets and liabilities	**1,486**	1,463
Valuation allowance	**(77)**	(55)
	7,921	7,733
Deferred income tax liabilities:		
Property, plant and equipment and intangible assets	**(2,747)**	(3,281)
Nuclear fixed asset removal and nuclear waste management funds	**(5,603)**	(5,390)
Other assets and liabilities	**(2,032)**	(1,211)
	(10,382)	(9,882)
Net deferred income tax liabilities	**(2,461)**	(2,149)

As of December 31, 2024, OPG has federal tax losses in the US of $504 million (2023 – $406 million) of which $8 million will expire in 2031 to 2037 if unused (2023 – $7 million). As of December 31, 2024, OPG has state tax losses in the US of $507 million (2023 – $460 million) of which $371 million will expire if unused in 2028 to 2044 (2023 – $308 million).

During 2024, OPG recorded an increase in the deferred income tax liability for income taxes that are expected to be recovered through regulated prices charged to customers of $213 million (2023 – $185 million) and a corresponding increase to the regulatory asset for deferred income taxes. As a result, the deferred income tax expense for 2024 and 2023 was not impacted.

The following table summarizes the deferred income tax liabilities recorded for the rate regulated operations that are expected to be recovered through future regulated prices:

(millions of dollars)	**2024**	**2023**
January 1:		
Deferred income tax liabilities on temporary differences related to regulated operations	**1,453**	1,314
Deferred income tax liabilities on temporary differences related to the regulatory asset for deferred income tax liabilities	**485**	439
	1,938	1,753
Changes during the year:		
Increase in deferred income tax liabilities on temporary differences related to regulated operations	**160**	139
Increase in deferred income tax liabilities on temporary differences related to the regulatory asset for deferred income tax liabilities	**53**	46
Balance as at December 31	**2,151**	1,938

The tax benefit associated with an income tax position is recognized only when it is more likely than not that such a position will be sustained upon examination by the taxing authorities based on the technical merits of the position. The current and deferred income tax benefit is equal to the largest amount, considering possible settlement outcomes, that is greater than 50 percent likely of being realized upon settlement with the taxing authorities.

A reconciliation of the beginning and ending amount of unrecognized tax benefits for the years ended December 31 were as follows:

(millions of dollars)	**2024**	**2023**
Unrecognized tax benefits, beginning of year	**84**	115
Additions	**7**	8
Reductions	**(16)**	(39)
Unrecognized tax benefits, end of year	**75**	84

As at December 31, 2024, OPG's unrecognized tax benefits were $75 million (2023 – $84 million), excluding interest and penalties, all of which, if recognized, would affect OPG's effective tax rate. Changes in unrecognized tax benefits over the next 12 months cannot be predicted with certainty.

OPG recognizes interest and penalties related to unrecognized tax benefits as income tax expense. As at December 31, 2024, OPG had recorded interest on unrecognized tax benefits of $20 million (2023 – $18 million). OPG considers its significant tax jurisdiction to be Canada for its Canadian entities, the US for its US subsidiaries and Romania for its Romanian subsidiary. OPG remains subject to income tax examination for years after 2019 in Canada, while certain of its wholly owned US subsidiaries are subject to federal and state income tax examinations for tax years after 2018 and 2017, respectively.

OPG paid $216 million in payments in lieu of income taxes, net of tax refunds, during 2024 (2023 – $441 million). OPG paid a negligible amount in Canadian federal and provincial income taxes, US federal and state income taxes and Romanian income tax during 2024 and 2023.

13. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The changes in the balance of each component of AOCI, net of income taxes, for the years ended December 31 were as follows:

	2024			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges**	**Pension and OPEB**	**Currency Translation Adjustment**	**Total**
Balance, beginning of year	**9**	**(33)**	**9**	**(15)**
Net gain on cash flow hedges	**1**	**-**	**-**	**1**
Actuarial gain on remeasurement of liabilities and past service costs for pension and OPEB	**-**	**41**	**-**	**41**
Amounts reclassified from AOCI	**(5)**	**(2)**	**-**	**(7)**
Translation of foreign operations	**-**	**-**	**173**	**173**
Other comprehensive (loss) income for the year	**(4)**	**39**	**173**	**208**
Balance, end of year	**5**	**6**	**182**	**193**

	2023			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges**	**Pension and OPEB**	**Currency Translation Adjustment**	**Total**
Balance, beginning of year	(6)	80	54	128
Net gain on cash flow hedges	11	-	-	11
Actuarial loss on remeasurement of liabilities and past service costs for pension and OPEB	-	(109)	-	(109)
Amounts reclassified from AOCI	4	(4)	-	-
Translation of foreign operations	-	-	(45)	(45)
Other comprehensive income (loss) for the year	15	(113)	(45)	(143)
Balance, end of year	9	(33)	9	(15)

The significant amounts reclassified out of each component of AOCI, net of income taxes, for the years ended December 31, were as follows:

	Amount Reclassified from AOCI		
(millions of dollars)	**2024**	**2023**	**Statement of Income Line Item**
Amortization of amounts related to cash flow hedges			
(Gains) losses	**(7)**	6	Revenue and Net interest expense
Income tax recovery (expense)	**2**	(2)	Income tax expense
	(5)	4	
Amortization of amounts related to pension and OPEB			
Net actuarial gains, net of past service credits	**(2)**	(5)	See (1) below
Income tax recovery	**-**	1	Income tax expense
	(2)	(4)	
Total reclassifications for the year	**(7)**	-	

[1] These AOCI components are included in the computation of pension and OPEB costs (see Note 14 for additional details).

14. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

Fund Assets

The OPG registered pension fund investment guidelines are stated in an approved Statement of Investment Policies and Procedures (SIPP). The SIPP is reviewed and approved by the Audit and Risk Committee of OPG's Board of Directors at least annually and includes a discussion of investment objectives and expectations, asset mix and rebalancing and the basis for measuring the performance of the pension fund assets.

In accordance with the SIPP, investment allocation decisions are made with a view to achieve OPG's objective of meeting obligations of the plan as they come due. The pension fund assets are invested in four categories of asset classes. The first category is fixed income assets, which are used to provide a ballast against heightened equity volatility in a slowing economic environment. The second category is equities, which offer the potential for higher investment returns beyond returns generally expected for fixed income assets. The third category is real assets, which offer exposure to a mixture of characteristics from the fixed income and equities. The fourth category is other alternatives, which offer the potential to improve the overall return of the pension fund while controlling the amount of downside market risk.

To achieve the above objective, OPG has adopted the following target strategic asset allocation for the OPG pension plan:

	Target
Asset class	
Fixed income assets	32.5%
Equities	33.0%
Real assets	32.5%
Other alternatives	2.0%

The plan may use derivative instruments for risk management or strategic purposes, where such activity is consistent with the plan's investment objectives.

Significant Concentrations of Risk in Fund Assets

The assets of the OPG pension fund are diversified to limit the impact of any individual investment. The pension fund is diversified across multiple asset classes. Fixed income securities are diversified among Canadian government bonds, government agency bonds, real return bonds, and corporate bonds. Equity securities are diversified across Canadian, US, and Global stocks. There are also real estate, infrastructure and agriculture portfolios that are included as part of the total pension fund assets as at December 31, 2024. Investments in the above asset classes are further diversified across funds, investment managers, strategies, vintages, sectors and geographies, depending on the specific characteristics of each asset class.

Credit risk with respect to the pension fund's fixed income securities is managed by risk tolerance guidelines, which require that fixed income securities comply with various investment constraints that ensure prudent diversification and prescribed minimum required credit rating quality. Credit risk, as it relates to the pension fund's derivatives, is managed through the use of International Swap and Derivatives Association documentation and counterparty management performed by the fund's investment managers.

Risk Management

Risk management oversight with respect to the OPG pension fund includes, but is not limited to, the following activities:

- Periodic asset/liability management and strategic asset allocation studies;
- Monitoring of funding levels and funding ratios;
- Monitoring compliance with asset allocation guidelines and investment management agreements;
- Monitoring asset class performance against asset class benchmarks;
- Monitoring investment manager performance against benchmarks; and
- Monitoring of risk tolerance guidelines.

Expected Rate of Return on Plan Assets

The expected rate of return on plan assets is based on the fund's asset allocation, as well as the return expectations considering long-term risks and returns associated with each asset class within the plan portfolio. The asset management decisions consider the economic liabilities of the plan.

Fair Value Measurements

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial instruments into three levels, based on the significance of inputs used in measuring the fair value of the assets and liabilities. Refer to Note 16 for a detailed discussion of fair value measurements and the fair value hierarchy.

The pension plan assets measured at fair value in accordance with the fair value hierarchy as at December 31 were as follows:

	2024			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and cash equivalents	**379**	**-**	**-**	**379**
Fixed income				
Corporate debt securities	**15**	**3,144**	**-**	**3,159**
Government bonds	**39**	**2,068**	**-**	**2,107**
Equities				
Canadian	**622**	**868**	**-**	**1,490**
US	**1,310**	**-**	**-**	**1,310**
Global	**560**	**-**	**-**	**560**
Pooled funds	**93**	**1,274**	**-**	**1,367**
	3,018	**7,354**	**-**	**10,372**
Forward foreign exchange contracts	**-**	**(110)**	**-**	**(110)**
Futures contracts and repurchase agreements	**-**	**(977)**	**-**	**(977)**
	3,018	**6,267**	**-**	**9,285**
Investments measured at NAV [1]				**8,496**
				17,781 [2]

	2023			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and cash equivalents	283	-	-	283
Short-term investments	-	4	-	4
Fixed income				
Corporate debt securities	13	2,981	-	2,994
Government bonds	30	2,028	-	2,058
Equities				
Canadian	670	597	-	1,267
US	1,082	-	-	1,082
Global	576	-	-	576
Pooled funds	86	1,279	-	1,365
Forward foreign exchange contracts	-	106	-	106
Futures contracts and repurchase agreements	1	-	-	1
	2,741	6,995	-	9,736
Futures contracts and repurchase agreements	-	(975)	-	(975)
	2,741	6,020	-	8,761
Investments measured at NAV [1]				7,842
				16,603 [2]

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to the total fair value of plan assets presented in tables following.

[2] The table above excludes pension fund receivables and payables.

Defined Benefit Plan Costs and Liabilities

Details of OPG's consolidated pension and OPEB obligations, pension fund assets and costs, together with the key assumptions used in determining these amounts, are presented in the following tables:

	Registered and Supplementary Pension Plans		Other Post-Employment Benefits	
	2024	**2023**	**2024**	**2023**
Weighted average assumptions – benefit obligations at year-end				
Discount rate for projected benefit obligation	**4.70 %**	4.64 %	**4.70 %**	4.64 %
Salary schedule escalation rate - initial rate [1]	**3.00 %**	3.25 %	**3.00 %**	3.25 %
- thereafter	**2.75 %**	2.75 %	**2.75 %**	2.75 %
Rate of cost of living increase to pensions	**2.00 %**	2.00 %	**2.00 %**	2.00 %
Initial health care trend rate	**n/a**	n/a	**5.40 %**	4.79 %
Ultimate health care trend rate	**n/a**	n/a	**4.05 %**	4.05 %
Year ultimate health care trend rate reached	**n/a**	n/a	**2040**	2040
Rate of increase in disability benefits	**n/a**	n/a	**2.00 %**	2.00 %

	Registered and Supplementary Pension Plans		Other Post-Employment Benefits	
	2024	**2023**	**2024**	**2023**
Weighted average assumptions – costs for the year				
Expected return on plan assets, net of expenses	**6.25 %**	6.25 %	**n/a**	n/a
Discount rate for current service cost	**4.62 %**	5.25 %	**4.61 %**	5.23 %
Discount rate for interest on projected benefit obligation	**4.63 %**	5.23 %	**4.63 %**	5.23 %
Discount rate for interest on current service cost	**4.63 %**	5.25 %	**4.63 %**	5.24 %
Salary schedule escalation rate - initial rate [1]	**3.25 %**	1.70 %	**3.25 %**	1.70 %
- thereafter	**2.75 %**	2.50 %	**2.75 %**	2.50 %
Rate of cost of living increase to pensions	**2.00 %**	2.00 %	**2.00 %**	n/a
Initial health care trend rate	**n/a**	n/a	**4.79 %**	4.17 %
Ultimate health care trend rate	**n/a**	n/a	**4.05 %**	4.05 %
Year ultimate health care trend rate reached	**n/a**	n/a	**2040**	2040
Rate of increase in disability benefits	**n/a**	n/a	**2.00 %**	2.00 %
Expected average remaining service life for employees (years)	**14**	13	**15**	14

n/a – assumption not applicable.

[1] Average rate per year to December 31, 2026.

	Registered Pension Plans		Supplementary Pension Plans		Other Post-Employment Benefits	
(millions of dollars)	**2024**	**2023**	**2024**	**2023**	**2024**	**2023**
Components of cost recognized for the year						
Current service costs	**305**	183	**8**	4	**99**	64
Interest on projected benefit obligation	**791**	785	**17**	16	**130**	128
Expected return on plan assets, net of expenses	**(1,031)**	(1,000)	**-**	-	**-**	-
Amortization of past service (credits) costs [1]	**(1)**	(1)	**-**	-	**2**	-
Amortization of net actuarial (gain) loss [1]	**-**	(1)	**4**	-	**(29)**	(52)
Recognition of LTD past service costs	**-**	-	**-**	-	**1**	-
Recognition of LTD net actuarial (gain) loss	**-**	-	**-**	-	**(26)**	39
Costs recognized [2]	**64**	(34)	**29**	20	**177**	179

[1] The net impact of amortization of net actuarial (gain) loss and amortization of past service (credits) costs was recognized as an increase to OCI. This increase was partially offset by the impact of the Pension and OPEB Regulatory Asset/Liability discussed in Note 7.
[2] Excludes the impact of regulatory accounts discussed in Note 7.

Total benefit costs, including the impact of the Pension and OPEB Cost Variance Account, the Pension & OPEB Cash Payment Variance Account and the Pension & OPEB Cash Versus Accrual Differential Deferral Account, for the years ended December 31 were as follows:

(millions of dollars)	**2024**	**2023**
Registered pension plans	**64**	(34)
Supplementary pension plans	**29**	20
Other post-employment benefits	**177**	179
Pension and OPEB Cost Variance Account	**68**	169
Pension & OPEB Cash Payment Variance Account	**12**	16
Pension & OPEB Cash Versus Accrual Differential Deferral Account	**11**	20
Pension and other post-employment benefit costs	**361**	370

The consolidated pension and OPEB obligations and pension fund assets measured as at December 31 were as follows:

	Registered Pension Plans		Supplementary Pension Plans		Other Post-Employment Benefits	
(millions of dollars)	**2024**	**2023**	**2024**	**2023**	**2024**	**2023**
Change in plan assets						
Fair value of plan assets, beginning of year	**16,636**	15,944	**-**	-	**-**	-
Contributions by employer	**206**	164	**17**	17	**119**	119
Contributions by employees	**121**	102	**-**	-	**-**	-
Actual return on plan assets, net of expenses	**1,668**	1,229	**-**	-	**-**	-
Benefit payments	**(825)**	(803)	**(17)**	(17)	**(119)**	(119)
Fair value of plan assets, end of year	**17,806**	16,636	**-**	-	**-**	-
Change in projected benefit obligations						
Projected benefit obligations, beginning of year	**17,158**	15,202	**378**	311	**2,770**	2,437
Employer current service costs	**305**	183	**8**	4	**99**	64
Contributions by employees	**121**	102	**-**	-	**-**	-
Interest on projected benefit obligation	**791**	785	**17**	16	**130**	128
Benefit payments	**(825)**	(803)	**(17)**	(17)	**(119)**	(119)
Past service costs	**15**	-	**-**	-	**24**	20
Net actuarial (gain) loss	**(96)**	1,689	**14**	64	**(56)**	239
Transfer in	**-**	-	**-**	-	**-**	1
Projected benefit obligations, end of year	**17,469**	17,158	**400**	378	**2,848**	2,770
Funded status – surplus (deficit), end of year	**337**	(522)	**(400)**	(378)	**(2,848)**	(2,770)

The pension and OPEB assets (liabilities) composition as at December 31 were as follows:

	Registered Pension Plans		Supplementary Pension Plans		Other Post-Employment Benefits	
(millions of dollars)	**2024**	**2023**	**2024**	**2023**	**2024**	**2023**
Non-current assets	**337**	-	**-**	-	**-**	-
Current liabilities	**-**	-	**(17)**	(17)	**(132)**	(129)
Non-current liabilities	**-**	(522)	**(383)**	(361)	**(2,716)**	(2,641)
Total assets (liabilities)	**337**	(522)	**(400)**	(378)	**(2,848)**	(2,770)

The accumulated benefit obligations for the registered pension plans and supplementary pension plans as at December 31, 2024 were $15,966 million and $341 million, respectively (2023 – $15,729 million and $332 million, respectively). The accumulated benefit obligation differs from the projected benefit obligation in that the accumulated benefit obligation includes no assumption about future compensation levels.

The projected benefit obligations for the registered pension plan and the supplementary pension plan increased from $17,158 million and $378 million as at December 31, 2023 to $17,469 million and $400 million as at December 31, 2024, respectively. The increase was mainly due to benefits earned for additional employee service and interest costs on the liabilities during 2024, partially offset by pension payments and a remeasurement of the benefit obligations reflecting higher discount rates at year-end 2024.

The projected benefit obligations for OPEB plans increased from $2,770 million as at December 31, 2023 to $2,848 million as at December 31, 2024. This increase was largely due to interest costs on the liabilities during 2024.

The following table provides the components of OPG's OCI related to pension and OPEB plans and the offsetting Pension and OPEB Regulatory Asset/Liability, discussed in Note 7, for the years ended December 31, on a pre-tax basis:

	Registered Pension Plans		Supplementary Pension Plans		Other Post-Employment Benefits	
(millions of dollars)	**2024**	**2023**	**2024**	**2023**	**2024**	**2023**
Changes in plan assets and benefit obligations recognized in OCI						
Current year net actuarial (gain) loss	**(733)**	1,460	**14**	64	**(30)**	200
Current year past service costs	**15**	-	**-**	-	**23**	20
Amortization of net actuarial gain (loss)	**-**	1	**(4)**	-	**29**	52
Amortization of past service credits (costs)	**1**	1	**-**	-	**(2)**	-
Total (increase) decrease in OCI	**(717)**	1,462	**10**	64	**20**	272
Less: (decrease) increase in Pension and OPEB Regulatory Asset *(Note 7)*	**(664)**	1,348	**9**	60	**20**	240
Net (increase) decrease in OCI (pre-tax)	**(53)**	114	**1**	4	**-**	32

The following table provides the components of OPG's AOCI and the offsetting Pension and OPEB Regulatory Asset/Liability that have not yet been recognized as benefit costs as at December 31, on a pre-tax basis:

	Registered Pension Plans		Supplementary Pension Plans		Other Post-Employment Benefits	
(millions of dollars)	**2024**	**2023**	**2024**	**2023**	**2024**	**2023**
Unamortized amounts recognized in AOCI						
Past service costs (credits)	**11**	(5)	**-**	-	**52**	31
Net actuarial loss (gain)	**504**	1,237	**97**	87	**(687)**	(686)
Total recognized in AOCI	**515**	1,232	**97**	87	**(635)**	(655)
Less: Pension and OPEB Regulatory Asset (Liability) *(Note 7)*	**473**	1,137	**90**	81	**(579)**	(599)
Net recognized in AOCI (pre-tax)	**42**	95	**7**	6	**(56)**	(56)

Details of the unamortized net actuarial loss (gain) and unamortized past service cost (credits) as at December 31 are as follows:

	Registered Pension Plans		Supplementary Pension Plans		Other Post-Employment Benefits	
(millions of dollars)	**2024**	**2023**	**2024**	**2023**	**2024**	**2023**
Net actuarial (gain) loss not yet subject to amortization due to use of market-related values	**(340)**	180	**-**	-	**-**	-
Net actuarial loss (gain) not subject to amortization due to use of the corridor	**853**	1,057	**40**	38	**(259)**	(251)
Net actuarial (gain) loss subject to amortization	**(9)**	-	**57**	49	**(428)**	(435)
Unamortized net actuarial loss (gain)	**504**	1,237	**97**	87	**(687)**	(686)
Unamortized past service costs (credits)	**11**	(5)	**-**	-	**52**	31

The most recently filed actuarial valuation, for funding purposes, of the OPG registered pension plan, as at January 1, 2024, was filed with the Financial Services Regulatory Authority of Ontario in September 2024. The next filed funding valuation must have an effective date no later than January 1, 2027. For 2025, the Company's estimated contribution to the OPG registered pension plan is expected to be $125 million.

As part of the actuarial valuation for funding purposes of the registered pension plan as at January 1, 2024, the plan's demographic and other assumptions were reviewed and revised, as necessary, by independent actuaries. Using updated demographic data as at January 1, 2024, and demographic assumptions consistent with the new funding valuation for the registered pension plan, OPG conducted a comprehensive actuarial valuation for accounting purposes of the OPG defined benefit pension and OPEB plans in 2024. The results of this valuation were reflected in the 2024 year-end obligations reflecting appropriate assumptions for accounting purposes as at December 31, 2024.

The supplementary pension plans are not funded, but are secured by letters of credit totalling $314 million as at December 31, 2024 (2023 – $308 million).

Estimated future benefit payments to participants in the pension and OPEB plans based on the assumptions used to measure the benefit obligations as at December 31, 2024 were as follows:

(millions of dollars)	Registered Pension Plans	Supplementary Pension Plans	Other Post-Employment Benefits
2025	871	18	132
2026	890	18	133
2027	899	19	136
2028	945	19	137
2029	942	19	139
2030 through 2034	5,107	101	749

A change in the following assumptions, holding all other assumptions constant, would increase (decrease) defined benefit pension and OPEB costs for the year ended December 31, 2024 as follows:

(millions of dollars)	Registered Pension Plans [1]	Supplementary Pension Plans [1]	Other Post-Employment Benefits [1]
Expected long-term rate of return			
0.25% increase	**(40)**	**n/a**	**n/a**
0.25% decrease	**40**	**n/a**	**n/a**
Discount rate			
0.25% increase	**(13)**	**(1)**	**(10)**
0.25% decrease	**14**	**1**	**11**
Inflation [2]			
0.25% increase	**60**	**2**	**1**
0.25% decrease	**(54)**	**(1)**	**(1)**
Salary increases			
0.25% increase	**16**	**4**	**1**
0.25% decrease	**(15)**	**(3)**	**(1)**
Health care cost trend rate			
1% increase	**n/a**	**n/a**	**66**
1% decrease	**n/a**	**n/a**	**(50)**

n/a – change in assumption not applicable.

[1] Excludes the impact of regulatory accounts.

[2] With a corresponding change in the salary increase assumption.

15. RISK MANAGEMENT AND DERIVATIVES

OPG is exposed to risks related to changes in market interest rates on debt, movements in foreign currency that affect the Company's assets, liabilities and forecasted transactions, and fluctuations in commodity prices. Select derivative instruments are used to manage such risks. Derivatives are used as hedging instruments, as well as for trading purposes.

Interest Rates

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in interest rates. Interest rate risk for OPG arises with the need to refinance existing debt or undertake new financing. The management of these risks includes using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

Foreign Exchange

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as certain materials, services and fuels purchased for generating stations and major development projects, as well as debt issuances, may be denominated in, or tied to, USD. To manage this risk, the Company may employ various financial instruments such as forwards and other derivative contracts, in accordance with approved corporate risk management policies. Additionally, volatility in the Canadian/US foreign exchange rate also impacts OPG's financial results from certain of its subsidiaries, whose operations are based exclusively in the US.

Commodity Prices

OPG is exposed to fluctuations in commodity prices. Changes in the market prices of nuclear fuels, oil, gas and biomass used to produce electricity can adversely impact OPG's earnings and cash flow provided by operating activities. To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts.

A number of OPG's hydroelectric facilities in the US are exposed to the wholesale electricity market and, therefore, are subject to volatility of wholesale electricity market pricing. Although revenue from these facilities represents a small portion of OPG's overall revenue, the Company may enter into derivative instruments from time to time to further mitigate this risk.

Credit

The Company's credit risk exposure is primarily a function of its electricity and other sales. The majority of OPG's revenue is derived from electricity sales through the IESO administered market. Market participants in the IESO market provide collateral in accordance with the IESO prudential support requirements to cover funds that they might owe to the market. Although the credit exposure to the IESO represents a significant portion of OPG's accounts receivable, the risk is considered acceptable due to the IESO's primary role in the Ontario electricity market. The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts at December 31, 2024 was less than $1 million (2023 − $1 million).

The fair value of the derivative instruments totalled a net liability of $17 million as at December 31, 2024 (2023 − $6 million).

The pre-tax amounts related to derivative instruments recorded in AOCI and net income for the years ended December 31 were as follows:

(millions of dollars)	**2024**	**2023**
Cash flow hedges (recorded in AOCI)		
Reclassification of (gains) losses to revenue and net interest expense	**(7)**	6
Commodity derivatives (recorded in net income)		
Realized losses in revenue	**(4)**	(16)
Unrealized losses in revenue	**(2)**	(10)

Existing pre-tax net losses of nil deferred in AOCI as at December 31, 2024 are expected to be reclassified to net income within the next 12 months.

16. FAIR VALUE MEASUREMENTS

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial assets and liabilities into three levels, based on the inputs used in measuring the fair value of the financial assets and liabilities. The fair value hierarchy has the following levels:

- Level 1: Valuation of inputs is based on unadjusted quoted market prices observed in active markets for identical assets or liabilities.
- Level 2: Valuation is based on inputs other than quoted prices under Level 1 that are observable for the asset or liability, either directly or indirectly.
- Level 3: Valuation is based on inputs for the asset or liability that are not based on observable market data.

The fair value of financial instruments traded in active markets is based on quoted market prices as at the consolidated balance sheet dates. A market is regarded as active if quoted prices are readily and regularly available from an exchange, dealer, broker, industry group, pricing service or regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's-length basis. The quoted market price used for financial assets held by OPG is the current bid price. These instruments are included in Level 1 and consist primarily of equity investments and fund investments.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing as at the consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives and fund investments. Various other fund investments are valued at the unit values supplied by the fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and, therefore, do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If all significant inputs required to fair value an instrument are observable, the instrument is included in Level 2.

If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. Specific valuation techniques are used to value these instruments. Significant Level 3 inputs include recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions and other relevant factors.

A summary of OPG's financial instruments and their fair value as at December 31 were as follows:

	Fair Value		Carrying Value [1]		
(millions of dollars)	**2024**	**2023**	**2024**	**2023**	**Balance Sheet Line Item**
Nuclear Segregated Funds (includes current portion) [2]	**22,412**	21,563	**22,412**	21,563	Nuclear fixed asset removal and nuclear waste management funds
Loan receivable − from Fair Hydro Trust	**828**	817	**902**	905	Loan receivable
Investment in Hydro One Limited Shares	**159**	164	**159**	164	Equity securities
Payable related to cash flow hedges	**-**	(1)	**-**	(1)	Long-term accounts payable and accrued charges
Long-term debt (includes current portion)	**(11,204)**	(9,793)	**(11,707)**	(10,342)	Long-term debt
Other financial instruments	**129**	107	**129**	107	Various

[1] The carrying values of other financial instruments included in cash and cash equivalents, receivables from related parties, other current assets, short-term debt, and accounts payable, accrued charges and other payables approximate their fair values due to the immediate or short-term maturity of these financial instruments.

[2] The Nuclear Segregated Funds are comprised of the Decommissioning Segregated Fund and the Used Fuel Segregated Fund. OPG's fair value of the Nuclear Segregated Funds is set not to exceed an amount equal to the funding liability pursuant to the ONFA when the Nuclear Segregated Funds are in a surplus position.

The fair value of OPG's long-term debt issued under the Medium Term Note Program is based on indicative pricing from the market. The fair value of these debt instruments is based on Level 2 inputs. The fair value of all other long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs.

The following tables present financial assets and financial liabilities measured at fair value in accordance with the fair value hierarchy as at December 31 were as follows:

	2024			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**7,030**	**6,676**	**-**	**13,706**
Investments measured at NAV [1]				**4,722**
				18,428
Due to Province				**(5,691)**
Used Fuel Segregated Fund, net				**12,737**
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**5,362**	**5,156**	**-**	**10,518**
Investments measured at NAV [1]				**3,702**
				14,220
Due to Province				**(4,545)**
Decommissioning Segregated Fund, net				**9,675**
Equity securities	**159**	**-**	**-**	**159**
Other financial assets	**73**	**-**	**97**	**170**
Liabilities				
Other financial liabilities	**(41)**	**-**	**-**	**(41)**

	2023			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	6,130	6,083	-	12,213
Investments measured at NAV [1]				4,277
				16,490
Due to Province				(4,232)
Used Fuel Segregated Fund, net				12,258
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	4,745	4,627	-	9,372
Investments measured at NAV [1]				3,341
				12,713
Due to Province				(3,408)
Decommissioning Segregated Fund, net				9,305
Equity securities	164	-	-	164
Other financial assets	71	4	82	157
Liabilities				
Other financial liabilities	(48)	(1)	(1)	(50)

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the consolidated balance sheets.

For the year ended December 31, 2024, there were no transfers between Level 1 and Level 2 and into or out of Level 3.

The changes in the net assets measured at fair value that are classified as Level 3 financial instruments for the year ended December 31, 2024 were as follows:

(millions of dollars)	**Other financial instruments**
Opening balance, January 1, 2024	**81**
Realized losses included in revenue	**(3)**
Unrealized gains included in revenue	**9**
Purchases	**10**
Closing balance, December 31, 2024	**97**

Investments Measured at Net Asset Value

Nuclear Segregated Funds

Nuclear Segregated Funds' investments classified as Level 3 consist of real estate, infrastructure, other real assets, and private debt investments. The fair value of these investments is determined using financial information as provided by the general partners of the limited partnership funds in which the Nuclear Segregated Funds are invested. Direct investments are valued using appropriate valuation techniques, such as recent arm's-length market transactions, references to current fair values of other instruments that are substantially the same, discounted cash flow analyses, third-party independent appraisals, valuation multiples, or other valuation methods. Any control, size, liquidity or other discount premiums on the investments are considered in the determination of fair value.

The process of valuing investments for which no published market price exists is based on inherent uncertainties and the resulting values may differ from values that would have been used had a ready market existed for these investments. The values may also differ from the prices at which the investments may be sold.

The classes of investments within the Nuclear Segregated Funds that are reported on the basis of Net Asset Value (NAV) as at December 31, 2024 were as follows:

(millions of dollars except where noted)	**Fair Value**	**Unfunded Commitments**	**Redemption Frequency**	**Redemption Notice**
Real assets				
Infrastructure	**4,661**	**1,656**	**n/a**	**n/a**
Real estate	**3,163**	**1,254**	**n/a**	**n/a**
Private debt	**182**	**598**	**n/a**	**n/a**
Other	**418**	**15**	**n/a**	**n/a**
Pooled funds				
Fixed income	**2,380**	**n/a**	**Daily**	**1-5 days**
Equity	**1,067**	**n/a**	**Daily**	**1-5 days**
Total	**11,871**	**3,523**		

The fair value of the pooled funds is classified as Level 2. Infrastructure, real estate, other real assets and private debt investments are measured using NAV as a practical expedient for determining their fair value.

Infrastructure

This class includes investments in funds whose investment objective is to generate a combination of long-term capital appreciation and current income, generally through investments such as energy, transportation and utilities. The fair values of investments in this class have been estimated using the NAV of the Nuclear Segregated Funds' ownership interest in these investments. The ownership interest in the respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their ownership interests to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Cash distributions are received based on the operations of the underlying investments and/or as the underlying investments are liquidated. It is not possible to estimate when the underlying assets of the infrastructure funds in this class will be liquidated.

Real Estate

This class includes investments in institutional-grade real estate property. The investment objective is to provide a stable level of income with an opportunity for long-term capital appreciation. The fair values of the investments in this class have been estimated using the NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in the respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their ownership interests to another party, as stipulated in the partnership agreements and/or shareholders' agreements. For investments in private real estate corporations, shares may be redeemed through a pre-established redemption process. Cash distributions are received based on the operations of the underlying investments and/or as the underlying investments are liquidated. It is not possible to estimate when the underlying assets in this class will be liquidated.

Other Real Assets

This class includes a diversified portfolio of real asset investments that are not classified in the real estate or infrastructure asset classes, such as agriculture and other private market partnership investments. The investment objective is to provide a differentiated return source, income yield and inflation protection. The fair values of the investments in this class have been estimated using the NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in the respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their ownership interests to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Cash distributions are received based on the operations of the underlying investments and/or as the underlying investments are liquidated. It is not possible to estimate when the underlying assets in this class will be liquidated.

Private Debt

This class represents investments in private indebtedness issued mainly by Canadian and US borrowers. The investment objective of private debt is to achieve income yield through a portfolio of professionally managed loans. The fair values of the investments in this class have been estimated using the NAV of the Nuclear Segregated Funds' ownership interest in these investments. Cash distributions are received based on the income of the loans and/or as the loans are matured or liquidated. There may be certain restrictions on the ability to sell the investments in this class.

Pooled Funds

This class represents investments in pooled funds, which primarily include a diversified portfolio of fixed income securities, issued mainly by Canadian corporations, and diversified portfolios of Emerging Market listed equity. The investment objective of the pooled funds is to achieve capital appreciation and income through professionally managed portfolios. The fair value of the investments in this class has been estimated using NAV per share of the investments. There are no significant restrictions on the ability to sell the investments in this class.

17. SHARE CAPITAL

Common Shares

As at December 31, 2024 and 2023, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value. Any issue of new shares is subject to the consent of OPG's shareholder, the Province.

Class A Shares

The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of non-voting Class A shares to the Province in exchange for equity injections in OPG. All of the outstanding shares are owned directly by the Province and OPG is authorized to issue an unlimited number of Class A shares without nominal or par value. The Class A and common shares rank equally as to entitlement to dividends, and all dividends declared by OPG must be declared in equal amounts per share on all outstanding shares without preference or distinction. Upon the liquidation, dissolution or wind-up of OPG, whether voluntary or involuntary, the holders of Class A shares and common shares are entitled to share equally, on a share-for-share basis, in all distributions of property and assets without preference or distinction. Any issue of new class of shares is subject to the consent of the Province. OPG is entitled to redeem outstanding Class A shares as may be approved by OPG's Board of Directors.

As at December 31, 2024 and 2023, OPG had 18,343,815 Class A shares issued and outstanding at a stated value of $787 million.

18. EARNINGS PER SHARE

Basic and diluted earnings per share are calculated by dividing net income attributable to the Shareholder by the weighted average number of shares outstanding.

Class A shares are included in the weighted average number of shares outstanding. The weighted average number of shares outstanding as at December 31, 2024 and 2023 was 274.6 million. There were no dilutive securities during the years ended December 31, 2024 and 2023.

19. COMMITMENTS AND CONTINGENCIES

Litigation

Various legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of business activities. These matters are subject to various uncertainties. Some of these matters may be resolved unfavourably. While it is not possible to determine the ultimate outcome of the various pending actions, it is the Company's belief that their resolution is not likely to have a material adverse impact on its consolidated financial position.

Guarantees

As at December 31, 2024, the total amount of guarantees provided by OPG was $30 million (2023 – $32 million). As at December 31, 2024, the potential impact of the fair value of the outstanding guarantees to income is $1 million and OPG does not expect to make any payments associated with these guarantees.

Contractual Obligations

OPG's contractual obligations as at December 31, 2024 were as follows:

(millions of dollars)	2025	2026	2027	2028	2029	Thereafter	Total
Fuel supply agreements	218	186	172	143	109	343	1,171
Contributions to the OPG registered pension plan [1]	125	128	-	-	-	-	253
Long-term debt repayment	604	674	530	269	505	9,168	11,750
Interest on long-term debt	439	421	410	392	379	5,153	7,194
Short-term debt repayment	215	-	-	-	-	-	215
Commitments related to Darlington Refurbishment project [2]	163	-	-	-	-	-	163
Commitments related to Atura Power development projects [2]	503	132	-	16	-	-	651
Commitments related to Pickering Refurbishment project and DNNP [2]	229	-	-	-	-	-	229
Operating licences	57	57	64	62	51	105	396
Operating lease obligations	15	14	11	4	3	36	83
Accounts payable, accrued charges and other payables	1,890	9	10	9	10	278	2,206
Other	50	71	49	33	20	89	312
Total	4,508	1,692	1,246	928	1,077	15,172	24,623

[1] Represents the estimated pension contributions consistent with the period covered by the actuarial valuation of the OPG registered pension plan as at January 1, 2024. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2027. Funding requirements after January 1, 2027 are excluded due to significant variability in the assumptions required to project the timing of future cash flows.

[2] Represents estimated currently committed costs to close the projects, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Contractual and commercial commitments as noted exclude certain purchase orders, as they represent purchase authorizations rather than legally binding contracts, and are subject to change without significant penalties.

Lease Commitments

The Company leases the Bruce nuclear generating stations to Bruce Power. Under the lease agreement, Bruce Power has options to renew the lease up to the end of 2064. As per *Ontario Regulation 53/05* pursuant to the *Ontario Energy Board Act, 1998*, the difference between OPG's revenues and costs associated with the Bruce nuclear generating stations is included in the determination of OPG's nuclear regulated prices established by the OEB. The OEB has determined that, since the Bruce nuclear generating stations are not prescribed under *Ontario Regulation 53/05*, these revenues, including lease revenues, and costs, including depreciation expense, are to be calculated on the basis of the manner in which they are recognized in OPG's consolidated financial statements, without the application of regulatory constructs. As such, the net book value of the assets for these stations is not included in the regulated rate base.

The net book value of PP&E on lease to Bruce Power as at December 31, 2024 was $1,633 million (2023 – $1,667 million). The net book value is largely comprised of asset retirement costs.

Collective Bargaining Agreements

The Company maintains labour agreements with the Power Workers' Union (PWU) and the Society of United Professionals (Society), which represent most of OPG's regular workforce.

As at December 31, 2024, the PWU represented approximately 5,180 regular and term-based employees, or 47 percent of OPG and its subsidiaries' regular workforce. Union membership includes station operators, technicians, skilled trades, clerical staff and security personnel.

The governing two-year collective agreement between the PWU and OPG expired on March 31, 2024. On November 20, 2024, the PWU membership ratified a three-year renewal collective agreement negotiated by the parties, covering the period from April 1, 2024 to March 31, 2027. The collective agreement provides for annual wage increases beginning April 1, 2024, and a lump sum payment to active employees effective November 20, 2024, and includes impacts arising in connection with the Ontario Superior Court's decision dated November 29, 2022 that found unconstitutional provincial legislation that set limits on compensation increases for employees in the Ontario public sector (Bill 124 Court Decision). On December 29, 2022, the Government of Ontario filed an appeal of the decision with the Ontario Court of Appeal. On February 12, 2024, the Ontario Court of Appeal upheld the lower court decision and found Bill 124 to be unconstitutional as it pertains to unionized employees but constitutional in its application to non-unionized employees. Following the decision, the Province repealed Bill 124 in its entirety. In 2023, the OEB denied OPG's request for a regulatory account to record compensation cost impacts attributable to the nuclear facilities as a result of the Bill 124 Court Decision subject to a future review and disposition by the OEB.

On July 19, 2024, the PWU-represented employees at the Brighton Beach GS ratified a two-year renewal collective agreement between the PWU and Atura Power, expiring on November 16, 2025. The governing collective agreement covering PWU-represented employees at Atura Power's other facilities expired on December 31, 2024, and negotiations for a renewal collective agreement are ongoing.

As at December 31, 2024, the Society represented approximately 4,000 regular and term-based employees, or 36 percent of OPG and its subsidiaries' regular workforce. Union membership includes supervisors, professional engineers, scientists and other professionals. The current two-year collective agreement between the Society and OPG expires on December 31, 2025.

In June 2023, the Society filed a related employer application with the Ontario Labour Relations Board. The application identified OPG and Atura Power as responding parties and asserted that they constitute a single employer for purposes of the Ontario *Labour Relations Act, 1995*, or in the alternative that a sale of business has occurred. Both OPG and Atura Power are opposing the application. Discussions are ongoing between the parties and two additional hearing dates have been scheduled in September 2025.

Contingencies

In the fourth quarter of 2023, Atura Power released a contingent liability recognized under a 2021 settlement agreement that related to certain post-closing activities of an acquisition of combined cycle plants, resulting in a pre-tax gain of $94 million.

20. BUSINESS SEGMENTS

As at December 31, 2024, OPG has the following five reportable business segments:

- Regulated – Nuclear Generation;
- Regulated – Nuclear Sustainability Services;
- Regulated – Hydroelectric Generation;
- Contracted Hydroelectric and Other Generation; and
- Atura Power.

The identification of business segments is based on a combination of revenue mechanisms and the type of electricity generation or the nature of services provided. Given the differences of the reportable segments, each segment is managed separately taking into account the distinct operational activities by type of electricity generation and services provided.

Regulated – Nuclear Generation Segment

The Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the Darlington and Pickering nuclear generating stations, both owned and operated by OPG. The business segment also includes revenue under the terms of a long-term lease arrangement and related non-lease agreements with Bruce Power related to the Bruce nuclear generating stations. This revenue includes lease revenue, fees for nuclear waste management services, and revenue from heavy water sales and detritiation services. The segment also earns revenue from regulated isotope sales contracts and from supplying ancillary services to the electricity system from the nuclear generating stations operated by OPG. Additionally, the segment includes expenditures related to SMRs at the DNNP site as these SMRs are prescribed for rate regulation by the OEB.

Regulated – Nuclear Sustainability Services Segment

OPG's Regulated – Nuclear Sustainability Services business segment reports the results of the Company's operations associated with the management of used nuclear fuel and L&ILW, the decommissioning of OPG's nuclear generating stations including the stations on lease to Bruce Power and other facilities, the management of the Nuclear Segregated Funds, and related activities including the inspection and maintenance of the used nuclear fuel and L&ILW storage facilities. Accordingly, accretion expense, which is the increase in the Nuclear Liabilities carried on the consolidated balance sheets in present value terms due to the passage of time, and earnings from the Nuclear Segregated Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs incremental costs related to used nuclear fuel and L&ILW, which increase the Nuclear Liabilities. OPG charges these incremental costs to current operations in the Regulated – Nuclear Generation business segment to reflect the cost of producing energy from the Darlington and Pickering nuclear generating stations and earning revenue under the Bruce Power lease arrangement and related agreements. Since the incremental costs increase the Nuclear Liabilities reported in the Regulated – Nuclear Sustainability Services business segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Sustainability Services business segments. The impact of the inter-segment charge is eliminated in the consolidated statements of income and balance sheets.

The Regulated – Nuclear Sustainability Services business segment is considered regulated because OPG's costs associated with the Nuclear Liabilities are included in the OEB's determination of regulated prices for electricity produced from the Darlington and Pickering nuclear generating stations.

Regulated – Hydroelectric Generation Segment

OPG's Regulated – Hydroelectric Generation business segment operates in Ontario, generating and selling electricity from most of the Company's hydroelectric generating stations. The business segment comprises the results of the 54 regulated hydroelectric generating stations located across a number of major river systems in the province. Additionally, the business segment includes revenues from supplying ancillary services to the electricity system and other revenues from OPG's regulated hydroelectric stations.

Contracted Hydroelectric and Other Generation Segment

The Contracted Hydroelectric and Other Generation business segment operates in Ontario and in the US, generating and selling electricity from the Company's non-regulated generating stations. The segment primarily includes generating facilities that operate under ESAs with the IESO. The majority of the facilities in the US currently supply energy and capacity into wholesale electricity markets. In Ontario, the current contracts for the thermal generating facilities are set to expire in 2029, for the solar facility in 2039 and for the hydroelectric facilities over the 2059 to 2067 period. In the US, the current contracts have expiration dates ranging from 2025 to 2043.

The Contracted Hydroelectric and Other Generation business segment includes OPG's share of equity income from co-owned and minority-held electricity generating facilities, and revenues from supplying ancillary services to the electricity system and other revenues from the stations included in the segment.

Atura Power Segment

The Atura Power business segment operates in Ontario, generating and selling electricity from the Company's fleet of combined cycle generating stations. All of the generating facilities included in the segment operate under ESAs with the IESO. The current contracts for these generating facilities are set to expire over the 2029 to 2040 period. The segment also includes revenues from participation in the IESO's operating reserve markets and generation cost guarantee programs. Additionally, the segment includes Atura Power's expenditures on business development projects, including low-carbon hydrogen production, battery energy storage systems (BESS) and combined cycle plant expansion.

Measure of Profit or Loss and Segment Assets

The Company evaluates performance of its reportable segments based on segment income or loss from operations before interest and income taxes.

The accounting policies of the reportable segments are the same as those described in the summary of significant accounting policies in Note 3.

Chief Operating Decision Maker and Use of Reported Measures

The Company's' Chief Operating Decision Maker (CODM) is comprised of the members of OPG's Enterprise Leadership Team. The CODM uses segment income or loss before interest and income taxes to assist in the allocation of resources (including employees, capital and financial resources). In addition, the CODM uses segment income or loss before interest and income taxes to assess performance of each segment by comparing results including variances with prior periods and other segments.

Service Fees

OM&A expenses of the regulated electricity generating business segments and the Contracted Hydroelectric and Other Generation business segment include a service fee for the use of certain shared PP&E and intangible assets held within the Other category. The service fee is recorded as an increase to revenue of the Other category, but is eliminated in the consolidated statements of income.

The service fees included in OM&A expenses by business segment for the years ended December 31 were as follows:

(millions of dollars)	**2024**	**2023**
Regulated – Nuclear Generation	**79**	75
Regulated – Hydroelectric Generation	**15**	14
Contracted Hydroelectric and Other Generation	**7**	6
	101	95

Segment Income (Loss) For the Year Ended December 31, 2024 *(millions of dollars)*	Regulated			Unregulated				
	Nuclear Generation	Nuclear Sustainability Services	Hydroelectric Generation	Contracted Hydroelectric and Other Generation	Atura Power	Other	Elimination	Total
Revenue	3,770	-	1,571	803	871	18	-	7,033
Leasing revenue	28	-	-	-	-	6	-	34
Other revenue	-	185	-	12	-	187	(264)	120
Total revenue	3,798	185	1,571	815	871	211	(264)	7,187
Fuel expense	288	-	335	59	367	-	-	1,049
Gross margin	3,510	185	1,236	756	504	211	(264)	6,138
Operations, maintenance and administration	2,474	185	413	307	98	105	(264)	3,318
Depreciation and amortization expenses	665	-	227	174	125	79	-	1,270
Accretion on fixed asset removal and nuclear waste management liabilities	-	1,210	-	9	2	-	-	1,221
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(1,102)	-	-	-	-	-	(1,102)
Property taxes	25	-	1	18	2	4	-	50
Other losses (gains) [1]	9	-	11	6	1	(8)	-	19
Income (loss) before interest and income taxes	337	(108)	584	242	276	31	-	1,362
Net interest expense [2]								186
Income before income taxes								1,176
Income tax expense								170
Net income								1,006

[1] A pre-tax loss totaling $25 million was recognized in Regulated – Nuclear Generation, Regulated – Hydroelectric Generation and Other in connection with the OEB's decision and order approving the 2024 Settlement Agreement during the second quarter of 2024.

[2] Further details on net interest expense can be found in Note 9.

Segment Income (Loss)	**Regulated**			**Unregulated**				
For the Year Ended December 31, 2023 *(millions of dollars)*	**Nuclear Generation**	**Nuclear Sustainability Services**	**Hydroelectric Generation**	**Contracted Hydroelectric and Other Generation**	**Atura Power**	**Other**	**Elimination**	**Total**
Revenue	4,251	-	1,485	784	789	16	-	7,325
Leasing revenue	26	-	-	-	-	5	-	31
Other revenue	-	203	-	31	-	133	(289)	78
Total revenue	4,277	203	1,485	815	789	154	(289)	7,434
Fuel expense	269	-	327	58	320	-	-	974
Gross margin	4,008	203	1,158	757	469	154	(289)	6,460
Operations, maintenance and administration	2,410	203	391	274	80	67	(289)	3,136
Depreciation and amortization expenses	527	-	181	165	121	77	-	1,071
Accretion on fixed asset removal and nuclear waste management liabilities	-	1,167	-	8	2	1	-	1,178
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(1,057)	-	-	-	-	-	(1,057)
Property taxes	25	-	1	18	3	1	-	48
Other losses (gains) [1,2]	-	-	9	4	(93)	(34)	-	(114)
Income (loss) before interest and taxes	1,046	(110)	576	288	356	42	-	2,198
Net interest expense [3]								103
Income before income taxes								2,095
Income tax expense								336
Net income								1,759

[1] Atura Power – a pre-tax gain of $94 million was recognized under a 2021 settlement agreement for certain post-closing activities of an acquisition of combined cycle plants in the fourth quarter of 2023.

[2] Other – a pre-tax gain for of $30 million was recognized on receiving an additional payment for the sale of the premises located at 800 Kipling Avenue in the second quarter of 2023.

[3] Further details on net interest expense can be found in Note 9.

Selected Consolidated Balance Sheets information as at December 31, 2024 *(millions of dollars)*	Regulated			Unregulated			
	Nuclear Generation	Nuclear Sustainability Services	Hydroelectric Generation	Contracted Hydroelectric and Other Generation	Atura Power	Other	Total
Segment property, plant and equipment in-service, net	14,046	-	8,189	6,322	3,033	224	31,814
Segment construction in progress	3,139	-	398	140	426	214	4,317
Segment property, plant and equipment, net	17,185	-	8,587	6,462	3,459	438	36,131
Segment intangible assets in-service, net	48	-	2	244	95	145	534
Segment development in progress	18	-	-	1	-	37	56
Segment intangible assets, net	66	-	2	245	95	182	590
Segment goodwill	-	-	-	230	-	-	230
Segment fuel inventory	231	-	-	39	27	-	297
Segment materials and supplies inventory							
Current	142	-	-	3	-	-	145
Long-term	352	-	-	3	-	-	355
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	-	22,412	-	-	-	-	22,412
Loan receivable	-	-	-	-	-	902	902
Fixed asset removal and nuclear waste management liabilities	-	(25,773)	-	(161)	(54)	(54)	(26,042)

Selected Consolidated Balance Sheets information as at December 31, 2023 *(millions of dollars)*	**Regulated**			**Unregulated**			
	Nuclear Generation	**Nuclear Sustainability Services**	**Hydroelectric Generation**	**Contracted Hydroelectric and Other Generation**	**Atura Power**	**Other**	**Total**
Segment property, plant and equipment in-service, net	12,434	-	8,016	5,868	3,027	237	29,582
Segment construction in progress	3,015	-	309	251	165	138	3,878
Segment property, plant and equipment, net	15,449	-	8,325	6,119	3,192	375	33,460
Segment intangible assets in-service, net	38	-	2	135	102	147	424
Segment development in progress	26	-	-	-	-	42	68
Segment intangible assets, net	64	-	2	135	102	189	492
Segment goodwill	-	-	-	168	-	-	168
Segment fuel inventory	243	-	-	29	23	-	295
Segment materials and supplies inventory							
Current	105	-	-	1	-	-	106
Long-term	380	-	-	2	-	-	382
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	-	21,563	-	-	-	-	21,563
Loan receivable	-	-	-	-	-	905	905
Fixed asset removal and nuclear waste management liabilities	-	(25,116)	-	(157)	(52)	(61)	(25,386)

Segment Capital Expenditure		**Regulated**	**Unregulated**				
(millions of dollars)	**Nuclear Generation**	**Nuclear Sustainability Services**	**Hydroelectric Generation**	**Contracted Hydroelectric and Other Generation**	**Atura Power**	**Other [1]**	**Total**
Year ended December 31, 2024							
Investment in property, plant and equipment and intangible assets	**2,535**	**-**	**434**	**220**	**382**	**154**	**3,725**
Net change in accruals and other non-cash items							**(188)**
Investment in property, plant and equipment and intangible assets – cash flow							**3,537**
Year ended December 31, 2023							
Investment in property, plant and equipment and intangible assets	1,859	-	370	313	148	139	2,829
Net change in accruals and other non-cash items							72
Investment in property, plant and equipment and intangible assets – cash flow							2,901

[1] Excludes the acquisition of the new corporate headquarters building and surrounding lands at 1908 Colonel Sam Drive in Oshawa, Ontario in February 2023.

21. RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One Limited (Hydro One), the IESO and the OEFC. Transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions for the years ended December 31 were as follows:

	2024		2023	
(millions of dollars)	**Income**	**Expense**	**Income**	**Expense**
Hydro One				
Electricity sales	**18**	**-**	16	-
Services	**-**	**9**	-	11
Dividends	**5**	**-**	5	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**1,137**	-	646
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**1,459**	-	820
Hydroelectric gross revenue charge	**-**	**118**	-	114
OEFC				
Hydroelectric gross revenue charge	**-**	**223**	-	216
Interest expense on long-term notes	**-**	**88**	-	94
Income taxes	**-**	**377**	-	526
Property taxes	**-**	**13**	-	13
IESO				
Electricity related revenue	**6,473**	**-**	6,694	-
Fair Hydro Trust				
Interest income	**33**	**-**	33	-
	6,529	**3,424**	6,748	2,440

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of any excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at December 31, 2024 and 2023, the Nuclear Segregated Funds were reported net of amounts due to the Province of $10,236 million and $7,640 million, respectively.

Balances between OPG and its related parties as at December 31 were as follows:

(millions of dollars)	**2024**	**2023**
Receivables from related parties		
Hydro One	**3**	4
IESO − Electricity related receivables	**608**	623
Fair Hydro Trust	**4**	4
Province of Ontario	**1**	-
Loan receivable		
Fair Hydro Trust	**902**	905
Equity securities		
Hydro One shares	**159**	164
Accounts payable, accrued charges and other payables		
Hydro One	**3**	2
OEFC	**85**	82
Province of Ontario	**10**	8
IESO − Electricity related payables	**-**	1
Long-term debt (including current portion)		
Notes payable to OEFC	**2,100**	2,500

OPG may hold Province of Ontario bonds and treasury bills in the Nuclear Segregated Funds and the OPG registered pension plan. As at December 31, 2024, the Nuclear Segregated Funds held $1,740 million of Province of Ontario bonds (2023 – $1,603 million) and $8 million of Province of Ontario treasury bills (2023 – $4 million). As of December 31, 2024, the OPG registered pension plan held $327 million of Province of Ontario bonds (2023 − $336 million) and $9 million of Province of Ontario treasury bills (2023 – $5 million). These Province of Ontario bonds and treasury bills are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

22. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

Years Ended December 31 *(millions of dollars)*	**2024**	**2023**
Receivables from related parties	**15**	(147)
Fuel inventory	**3**	(47)
Materials and supplies	**(34)**	29
Prepaid expenses	**5**	(66)
Other current assets	**(32)**	144
Accounts payable, accrued charges and other payables	**(18)**	(27)
Net changes in non-cash working capital balances	**(61)**	(114)

23. NON-CONTROLLING INTEREST

Lower Mattagami LP

LMLP is a limited partnership between OPG and Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation. The principal business of the partnership is the development, construction, ownership, operation and maintenance of 490 megawatts (MW) of hydroelectric generating capacity on the Lower Mattagami River located in Ontario, which includes generating units at Smoky Falls, Little Long, Harmon and Kipling hydroelectric generating stations. OPG owns approximately 75 percent of the equity interest in LMLP. OPG consolidates the results of LMLP in its consolidated financial statements and reports the equity interest of the other partner as non-controlling interest.

PSS Generating Station LP

PSS is a limited partnership between OPG and a corporation wholly owned by the Taykwa Tagamou Nation. The principal business of the partnership is the development, construction, ownership, operation and maintenance of the 28 MW Peter Sutherland Sr. hydroelectric GS on the New Post Creek located in Ontario. OPG owns approximately 67 percent of the equity interest in PSS. OPG consolidates the results of PSS in its consolidated financial statements and reports the equity interest of the other partner as non-controlling interest.

Nanticoke Solar LP

Nanticoke Solar LP (NSLP) is a partnership between OPG, a corporation wholly owned by the Six Nations of the Grand River Development Corporation, and the Mississaugas of the Credit First Nation. The partnership operates a 44 MW solar facility at OPG's former Nanticoke GS site and adjacent lands located in Ontario. OPG owns 80 percent of the equity interest in NSLP. OPG consolidates the results of NSLP in its consolidated financial statements and reports the equity interest of the other partners as non-controlling interest.

Little Falls Hydroelectric Associates, LP

OPG, through Eagle Creek, has an 83 percent interest in the Little Falls Hydroelectric Associates, LP. The partnership operates the 14 MW Little Falls hydroelectric GS located in New York State, US. OPG consolidates the results of Little Falls Hydroelectric Associates, LP in its consolidated financial statements and reports the equity interest of the other partners as non-controlling interest.

Napanee BESS Inc. and Atura Hydrogen Inc.

In 2023, the Company, through Atura Power, entered into partnerships with Ameresco BESS Holdings Inc., a subsidiary of Ameresco Inc., to undertake projects to build a battery energy storage system and hydrogen production facilities. As part of these partnerships, OPG owns approximately 90 percent of the voting interest in Napanee BESS Inc., which is undertaking the project to build a 250 MW four-hour BESS at the Napanee GS site under a long-term agreement with the IESO, and owns 89 percent of the voting interest in Atura Hydrogen Inc., which is developing the Niagara Hydrogen Centre, a large-scale low-carbon hydrogen production facility in Niagara Falls, Ontario. OPG consolidates the results of Napanee BESS Inc. and Atura Hydrogen Inc. in its consolidated financial statements and reports the equity interests of the other partners as non-controlling interest.

24. PURCHASE AND SALE OF REAL ESTATE SITES

In February 2023, OPG acquired the building and surrounding lands at 1908 Colonel Sam Drive in Oshawa, Ontario, for $102 million. The building is being retrofitted prior to occupancy and will serve as the Company's new corporate headquarters.

25. SALE OF ASSETS

In July 2023, Eagle Creek entered into agreements to sell 22 hydroelectric generating stations in the US with a total generating capacity of approximately 47 megawatts across a number of regions, along with two storage reservoirs in the Mid-Western US. While the transaction was being negotiated and closed, the assets were no longer depreciated or amortized, and were held within other current assets on the consolidated balance sheets within the Contracted Hydroelectric and Other Generation business segment.

In June 2024, the transaction was terminated. Following the termination, the criteria for classifying these assets as held for sale were no longer met, and, during the second of quarter of 2024, the assets were reclassified to PP&E and intangible assets on the consolidated balance sheets. The assets' net book values have been adjusted for depreciation and amortization expense that would have been recognized had the assets continued to be classified as PP&E and intangible assets during the period that they were considered held for sale. The assets continue to be valued at the lower of carrying value and fair value.

BUSINESS PLANNING AND BUDGETING

1.0 PURPOSE

This evidence presents an overview of Ontario Power Generation's ("OPG" or the "Company") business planning and budgeting objectives, and the planning process that underpins this Application.

2.0 OVERVIEW

The revenue requirements requested in this Application are based on OPG's 2025-2031 Business Plan (the "Plan"), which is filed as Attachment 1 to this schedule.

The Plan covers a transformative period for Ontario's energy sector and its economy – a period in which OPG has been tasked with delivering approximately $30 billion of capital investments that will serve as a foundation for the Province of Ontario's ("Province") plan for an energy system "rooted in the province's ability to deliver power that is affordable, secure, reliable, and clean".[1] These investments are critical for meeting the province's growing demand for electricity, which the Independent Electricity System Operator ("IESO") forecasts will increase from approximately 151 TWh in 2025 to 250 TWh in 2050 – an increase of 65%.[2]

The Minister of Energy and Mines (the "Minister") is ultimately responsible for determining how Ontario's electricity supply mix will be structured to meet these challenges. The Government of Ontario's 2025 Integrated Energy Plan ("IEP") has affirmed that the province's nuclear generating stations will continue to serve as the "backbone of the province's electricity system", providing "clean, affordable, and reliable nuclear power" to meet the growing demand.[3] To that end, the Minister has approved OPG to proceed with the largest components of OPG's Plan and this Application, including the Pickering Refurbishment Program ("PRP"),[4] the Darlington

[1] "Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7", Ministry of Energy and Mines, p.6 [IEP].
[2] "Annual Planning Outlook: 2026 Demand Forecasts & 2027 Demand Scenario", IESO, November 2025, p. 6.
[3] IEP, p. 42.
[4] Province of Ontario, Press Release: Ontario Advancing Plan to Refurbish Pickering Nuclear Generating Station, January 23, 2023. Province of Ontario, Press Release: Ontario Greenlights Pickering Nuclear Generating Station Refurbishment to Create Nearly 37,000 Jobs, November 26, 2025.

New Nuclear Program ("DNNP"),[5] and the planned investments in the Company's hydroelectric facilities.[6] OPG is committed to delivering these mega-projects or programs safely, at its high standards of operational and project excellence, with value to customers. Meeting Ontario's future electricity demand and energy security needs also requires OPG to make material investments in sustaining its existing regulated facilities, its technology and in its corporate resources, and to maintain a highly skilled, engaged workforce.

The Plan is designed to meet the province's needs, and doing so will require OPG to undertake multiple mega-projects concurrently, including the refurbishment of Pickering Generating Station Units 5-8, the construction of the Group of Seven countries' first small modular reactor ("SMR") through the DNNP, and continued investment in refurbishing and redeveloping the Company's 90-year old regulated hydroelectric fleet. OPG will meet the challenges of this period by leveraging the skills that its workforce has built through the successful execution of the Darlington Refurbishment Program ("DRP"), which is forecasted to be completed under the $12.8 billion budget previously approved by the OEB.

Delivering these significant investments will require OPG to transform and evolve. In the Company's prior payment amounts application to the Ontario Energy Board ("OEB"), OPG's business plan focused on managing the downsizing that was required to align with the then-anticipated shutdown of Pickering. In contrast, OPG must now strive to ensure that its operational, project, technology, workforce, and financial resources are sufficient to deliver the projects planned for the next seven years, and to reliably and efficiently operate the new and refurbished facilities.

While delivering an investment program on this scale would always be challenging, the current economic and geopolitical environment poses additional challenges. OPG must manage the heightened supply and procurement risks associated with high-demand materials and equipment, and must compete to secure the skilled resources that are in increasing demand as large-scale infrastructure and energy projects ramp-up across Canada and beyond. OPG

[5] Province of Ontario, Press Release: Ontario Leads the G7 by Building First Small Modular Reactor, May 8, 2025.
[6] Province of Ontario, Powering Ontario's Growth: Ontario's Plan for a Clean Energy Future, July 7, 2023.

also must continue to navigate a complex labour relations landscape with its union partners. As it advances the Plan, OPG remains committed to continuing to engage with Ontario's Indigenous communities, including in developing commercial partnerships and collaborative structures that will create social and economic benefits and help deliver the Company's significant work program.

Consistent with the Company's culture of operational excellence, the Plan sets ambitious but achievable cost and operational targets for the nuclear and regulated hydroelectric facilities over the IR term. These targets include:

- Base operations, maintenance and administration ("OM&A") cost budgets that reflect the resources required to ensure ongoing safe and reliable operations and meet Ontario's electricity demand and energy security needs, support OPG's commitment to innovation and continuous improvement, maintain the long-term value of the Company's assets, and manage organizational risks.
- Generation reliability performance for regulated operations over the IR term with a forced loss rate target of 2.0% for Darlington[7] and a hydroelectric availability target of 84% on average[8].
- Excluding the PRP, the DNNP and the DRP, investment in the nuclear business of $5.2 billion over the IR term including $2.6 billion for the Darlington and Pickering project portfolios. While the previously anticipated projects in preparation for Darlington's "second life" are being completed, to maintain strong operational performance, certain major investments are necessary to address emergent reliability risks to the station's post-refurbishment operations. Through execution of these projects, OPG is prudently managing these identified risks. The restarted Pickering Program ramps up in contemplation of post-refurbishment operations of Units 5-8.
- Investment in the regulated hydroelectric fleet of approximately $4.8 billion over the IR term, comprising investments of $1.6 billion for the fleet-wide project portfolio, $2.2 billion for the ongoing refurbishment program, $0.3 billion for redeveloping and expanding certain

[7] Excluding the temporarily higher forced loss rate expected immediately after refurbishment based on industry operating experience, as described in Ex. E2-1-1.
[8] The regulated hydroelectric availability target reflects outages required to execute on the major turbine-generator refurbishment program, as described in Ex. F1-1-1.

smaller facilities, $0.5 billion for major rehabilitation work at the Abitibi Canyon station, and $0.2 billion for major infrastructure work on the Sir Adam Beck power canal.

- Achieving second quartile normalized Total Generating Cost ("TGC") per MWh performance for Darlington toward the end of the IR term as the major emergent reliability projects are completed, positioning the station for further improvement going forward.[9]
- Maintaining strong performance on safety and reliability metrics and supporting favourable cost benchmarking results for the regulated hydroelectric facilities relative to peer utilities.
- Maintaining OPG's corporate credit ratings, to the extent possible, to support the Company's continued ability to access cost effective financing, which benefits ratepayers.

Maintaining industry-leading safety performance continues to be a paramount objective for OPG's facilities. In 2024, OPG hosted a World Association of Nuclear Operators mid-cycle site visit at Pickering. At Darlington, OPG most recently hosted a World Association of Nuclear Operators continuum site visit in the second quarter of 2025. Through these visits, both nuclear stations were recognized as performing at the highest levels of operational safety and reliability. For Darlington, this was the thirteenth consecutive year of receiving such recognition. In the fourth quarter of 2025, Pickering station will host a World Association of Nuclear Operators peer review. These reviews include an international safety assessment of the nuclear power plant conducted by an expert team to evaluate operations and recommend improvements.

In addition to issuing debt, the Plan relies on several methods to help finance the Company's operations and investments over the period. This includes:

- The assumed introduction of a new regulatory mechanism for the concurrent cost recovery ("CCR") of debt financing costs during the construction of the DNNP and the PRP.[10]
- An anticipated shareholder equity injection in the Company, totalling $5 billion over the 2025-2027 period, reducing OPG's borrowing requirements and supporting OPG's credit ratings.
- OPG's announced equity partnership with Canada Growth Fund and Building Ontario Fund as minority investors in the DNNP which, subject to satisfaction of conditions, is expected

[9] The methodology for normalizing the TGC per MWh metric is discussed in Ex. F2-1-1.
[10] The concurrent cost recovery mechanism established by O. Reg. 53/05 is discussed in Ex. I1-1-3.

to contribute approximately $3 billion of funding in the Plan. The partnership will lease the assets from OPG, who will continue to be the Canadian Nuclear Safety Commission ("CNSC") licence holder, project manager, and operator of the facility. The Plan expects DNNP LP to be a newly prescribed generator under O. Reg. 53/05 and to enter into a lease for the DNNP facilities with OPG. DNNP LP will undertake the development, construction, and operation of the DNNP facilities, with OPG contracted to act as the project manager and operator of the facilities. The costs and resources forecasted associated with the DNNP LP are reflected in the Plan.

The federal government has proposed a 15% refundable tax credit for certain clean electricity investments ("CEITC"), including eligible hydroelectric systems and nuclear energy equipment, that could be available to OPG and would reduce borrowing requirements. At the time of filing, no legislation implementing this credit is in place and the CEITCs are not reflected in OPG's 2025-2031 Business Plan. OPG will account for such credits as a reduction in the capital costs of the underlying projects. The Application proposes to return to customers the revenue requirement of the CE-ITCs, once available, through a series of variance accounts. The CEITCs are discussed further in Ex. F4-2-1, Section 3.6.1.

Notwithstanding the above tools, increasing debt levels associated with the planned capital investments are expected to continue to put pressure on the Company's current credit ratings, with the three major rating agencies (S&P, Moody's, and DBRS) identifying increasing pressure on OPG's credit metrics during the Plan period.

As shown in in Ex. I1-1-2, the impact of the proposed payment amounts and payment rider changes on the total monthly bill for a residential electricity consumer is, on average, approximately 2.4% over the five-year IR term. However, the total bill impact for such consumers in 2027 is higher than the average. Without any form of payment amount shaping, the 2027 total bill increase would be approximately 7.3%. This one-year increase is primarily due to a temporary decrease in Darlington generation as a result of a unique combination of planned outages in that year, including the four-unit vacuum building outage that is a regulatory requirement of the CNSC. To help manage this impact while balancing OPG's financing needs,

the Application proposes to defer the collection o500M in OPG's nuclear revenue requirement from 2027 to 2028, as described in Ex. I1-3-2. This approach lowers the 2027 residential total bill impact to approximately 5.6%. To inform this payment amount-shaping proposal, OPG engaged Innovative Research Group Inc. ("INNOVATIVE") to survey residential customers on their preferences as between multiple options. INNOVATIVE found that a plurality of customers supported at least some degree of rate-shaping.[11] This customer input, along with financial viability considerations, led to the proposed payment amount shaping approach described in Ex. I1-3-2.

Financial information in the Plan is presented on the basis of generally accepted accounting principles in the United States ("US GAAP"), which is and expected to remain OPG's financial reporting framework for the reasons discussed in Ex. A2-1-1. While the financial results of DNNP LP will be consolidated in OPG's financial statements for financial reporting purposes, going forward DNNP LP will also have its own audited annual financial statements, a separate business plan and, subject to the OEB's approval, standalone regulatory reporting (Ex. A1-3-2, Section 5.4.1).

The remainder of this schedule is organized as follows:

- Section 3.0 summarizes major elements of the 2025-2031 Business Plan.
- Section 4.0 summarizes OPG's business planning process.
- Section 5.0 summarizes the incorporation of customer and community engagement in OPG's business planning process.

3.0 BUSINESS PLAN SUMMARY

This Business Plan period will encompass completion of major nuclear and regulated hydroelectric capital investments that enter rate base. OPG will continue to focus on prudent cost management and productivity improvement, while ensuring that it operates in a safe, reliable, and environmentally and socially responsible manner.

[11] INNOVATIVE's report on this research is filed as Ex. I1-3-2, Attachment 1.

Key elements of the 2025-2031 Business Plan are:

1. Investing to Meet Ontario's Energy Demand and Energy Security Needs
2. Resourcing Strategy
3. Financing and Credit Ratings
4. Indigenous Relations
5. Continuous Improvement
6. Nuclear Liabilities

Each element is described below.

3.1 Investing to Meet Ontario's Energy Demand and Energy Security Needs

The Plan includes transformational investments OPG is making in the province's electricity system, reflecting the Company's role in serving Ontario's electricity demand. These investments will ensure that OPG's nuclear and regulated hydroelectric assets are available to safely, reliably, and cost effectively meet the needs of electricity consumers over the near and longer term. The Minister has approved OPG to proceed with the largest components of OPG's Plan and this Application. The planned investments in the regulated business over the IR term are approximately $30 billion and include the following: (i) the PRP, (ii) the DNNP, (iii) completing the DRP, and (iv) sustaining capital investments. Each category is summarized below.

3.1.1 Pickering Refurbishment

In January 2025, the Province announced its approval of OPG's plan to proceed with the project definition phase as the next step toward refurbishing Pickering Units 5-8 after they reach the end of their "first life" operations in September 2026. In June 2025, OPG submitted an application to the CNSC for renewal of Pickering's operating licence, which includes the planned refurbishment activities. Based on detailed engineering and work planning, OPG has prepared the Release Quality Estimate ("RQE") for the four-unit refurbishment which was approved by the OPG Board of Directors, and announced by the Province, in November 2025.

The Plan reflects the high-confidence cost estimate and schedule in the RQE, with the project prepared to progress into the execution phase beginning in 2027. Based on the high-confidence schedule, the first unit, Unit 5, will return to service in May 2031 and all four units will be completed by 2034. Unlike the DRP, the PRP will execute overlapping work on all four units, with project expenditures peaking during the IR term as a result.

The high-confidence budget for the four-unit refurbishment is $26.8 billion.[12] The forecasted capital in-service amount for Unit 5 and pre-requisite projects is $9.7 billion during the IR term, which excludes interest amounts to be recovered under the CCR framework.

3.1.2 Darlington New Nuclear Program

In March 2025, OPG's Board of Directors approved the RQE and associated funding release for the execution of the first of four SMRs and common site scope at OPG's Darlington New Nuclear Site ("Unit 1"). In April 2025, the CNSC announced its decision to issue a power reactor construction licence to OPG for Unit 1, valid until March 2035. In May 2025, the Province announced its support for OPG to proceed with the execution phase of Unit 1.

The Plan reflects the high-confidence cost estimate and schedule in the RQE, with the project currently progressing through construction. Based on the high-confidence schedule, Unit 1 will enter commercial operation in October 2030. While the Plan includes capital expenditures and staffing resources for the potential construction of subsequent DNNP units, they are subject to future requisite approvals and are not included in this Application.[13] OPG expects to file an operating licence application for the first SMR with the CNSC in 2026.

The high-confidence budget for Unit 1 is $7.7 billion, of which $1.6 billion is allocated to site scope common to all four planned DNNP units.[14] The forecasted capital in-service amount for

[12] Including interest on the expenditures.
[13] In accordance with O. Reg. 53/05, DNNP LP is permitted to recover a CCR amount calculated by multiplying actual cumulative capital costs incurred in respect of the DNNP by OPG's long-term debt rate. This is provided through (i) a provision allowing recovery through payment amounts based on a forecast of capital expenditures (in this Application, related primarily to Unit 1) and (ii) through a variance account recording the difference between the CCR amount calculated in (i) and a CCR amount based on actual expenditures.
[14] Including interest on the expenditures.

Unit 1 is $6.6 billion during the IR term, which excludes interest amounts to be recovered under the CCR framework.

3.1.3 Completing Darlington Refurbishment

The Plan reflects capital expenditures to complete the DRP in 2026. In November 2024, OPG successfully reconnected the refurbished Darlington 1 to the grid, ahead of original schedule. This followed the early return to service of Unit 3 in 2023. The last unit, Unit 4, is expected to return to service by April 2026, also ahead of schedule. Through performance-based savings since the completion of the first unit, Unit 2, OPG is now tracking to successfully mitigate the cost impact of the COVID-19 pandemic and elevated inflation, and complete the project within the $12.8 billion budget previously approved by the OEB. OPG will leverage the benefits of experience and lessons learned from the DRP, as applicable, for the PRP and the DNNP.

3.1.4 Sustaining Capital Investments

Maintaining the availability and reliability of OPG's existing fleet is a critical component of meeting Ontario's current and future energy needs. OPG's sustaining investments are based on asset management principles aimed at ensuring capital is deployed in a manner that derives the greatest value while mitigating operational risks. Over the IR term, OPG plans to invest approximately $11 billion in sustaining expenditures, including $5.2 billion for the nuclear fleet, $4.8 billion for the regulated hydroelectric assets, and $1.1 billion in digital technology projects and other corporate investments.

Darlington Sustaining Capital: The Darlington capital program will continue to focus on ensuring that the refurbished station is well positioned for sustained strong performance over the long term by making investments necessary to address emergent reliability risks. In addition to an ongoing sustaining portfolio, this includes several major non-portfolio projects: the Darlington turbine rotor replacements, the Darlington steam generator primary moisture separator replacements, the Tritium Removal Facility Major Component Replacement, the Darlington Unit 2 turbine control and auxiliary system upgrade, and the Darlington Units 1 and 2 generator stator rewind. These projects include major replacements, rehabilitations, and upgrades to ensure Darlington sustains safe and reliable operations, and the continued

availability of the Tritium Removal Facility to supply de-tritiated heavy water to Ontario's CANDU fleet.

Pickering Sustaining Capital: The Pickering sustaining capital program represents a change from recent years, when very limited sustaining work was conducted due to the assumed end of commercial operation. Over the IR term, the larger Pickering capital portfolio program will now focus on sustaining work that is more efficiently executed during the multi-unit refurbishment window, supports improved post refurbishment unit reliability, and renews station infrastructure, with scope clearly delineated from the Pickering refurbishment that will focus on critical life-limiting components and completion of upgrades to meet regulatory requirements.

Regulated Hydroelectric Sustaining Capital: OPG's regulated hydroelectric generating facilities remain a central pillar of Ontario's renewable, low-cost, practically zero-emissions electricity supply. OPG is continuing a major program of turbine-generator refurbishment projects in order to maintain the fleet's reliability and maximize the ability to support increasing electricity demand. The forecasted refurbishment expenditures are $2.2 billion over the IR term. The plan also includes funding for major civil infrastructure projects and the first two phases of work on the 100-year-old canal that supplies water from the Welland and Niagara Rivers to the Sir Adam Beck generating complex.

OPG continues to evaluate the condition and redevelopment potential of the regulated hydroelectric fleet as some of the oldest, smaller facilities approach end of life. The plan reflects the redevelopment of five such facilities currently in the execution phase based on the applicable cost and schedule commitments as approved by the OPG Board of Directors.

Information Technology: OPG will also refresh digital technology systems according to their lifecycle as well as invest in technology enhancements to support operations and projects and emerging needs during the IR term. A key component of the Company's digital strategy is to update and improve enterprise resource planning and asset management systems, which will address obsolescence risks and provide an opportunity to streamline processes and enable

efficiencies. OPG will also invest in technological solutions related to cyber security, operations, engineering technology, and data management. With respect to the DNNP, the plan includes a dedicated funding stream to enable a digital strategy for the SMRs.

3.1.5 Inflationary Impacts

During the IR term, OPG has faced inflationary pressures far exceeding historical norms. While prior Consumer Price Index ("CPI") trends suggested a 2.5% annual increase, the construction industry had been experiencing escalation rates closer to 7.5%, driven by global and domestic factors. These included persistent inflation, supply chain disruptions, geopolitical factors, and tariffs impacting material costs. Large-scale infrastructure projects have been particularly affected, as reflected in industry benchmarks like Turner's Building Cost Index and Rider Levett Bucknall reports, which show year-over-year increases of 5-6% or higher. This environment has created increased cost volatility, making traditional CPI-based assumptions inadequate for capital planning.

To address these risks, OPG conducted a comprehensive review supported by independent analysis, confirming sustained escalation pressures through 2031 for construction material. Accordingly, OPG reflected procurement-related inflation considerations into the capital plan based on existing commercial agreements or supplier estimates, and otherwise applied a standardized 4.5% escalation rate.[15] This reflects a balanced approach acknowledging industry realities while ensuring fiscal discipline and working with suppliers to share in the burden where possible. These measures strengthen the resilience of OPG's capital program and ensure alignment with validated market data, positioning the organization to manage ongoing cost escalation effectively while fostering shared accountability across the supply chain.

3.2 Resourcing Strategy

OPG's resourcing plan and operating cost projections reflect a transition from an organization that was preparing for downsizing approximately 3,000 positions as a result of the planned Pickering shutdown to one that is now entering a period of significant investment. To meet this

[15] Attachment 2, Section 1.3

mandate, OPG must ensure it maintains the necessary skilled workforce, while operating within complex collective agreements covering most of its workforce. Strategic workforce planning is required in support of the transitional period between the shutdown of Pickering Units 5-8 in 2026 and return of Unit 5 to service in May 2031.

OPG requires a smooth workforce transition through the Pickering refurbishment period and has secured the necessary labour agreements to enable a minimally disruptive, cost-effective, and timely redeployment of employees from Pickering operations to the PRP and other parts of the organization where resources are needed. This workforce transition will benefit the execution of the PRP by incorporating staff with relevant expertise and knowledge of the station to meet the demands of the PRP schedule and execute certain work more efficiently. This will also support business continuity by retaining valuable resources that will be needed to operate the station once Unit 5 is refurbished, avoiding incremental costs and mitigating operational risks. Taking into account these workforce transitions, OPG's overall staffing level is expected to remain steady throughout the IR term.

Although all four units at Pickering will be under refurbishment during the IR term, some staff will continue to be necessary to maintain Units 5-8 and the associated infrastructure to support readiness for return to service, while ensuring ongoing compliance with site licence requirements. The site licence conditions continue to apply to Pickering throughout the refurbishment outages as do OPG's internal aging management programs. This requires OPG to retain applicable resources for the station in areas such as engineering, fleet maintenance, site security and emergency preparedness, environmental health and safety, and other support, during the four-unit refurbishment outage.

3.3 Financing and Credit Ratings

As OPG advances its capital program over the IR term, the Company is facing an increase in financing requirements due to the scale of its required investments in the electricity system. Debt financing remains the Company's primary source of external financing. OPG's credit ratings are a key determinant of its cost of debt and maintaining a strong credit rating is essential to the Company's ability to access cost effective borrowing. As OPG undertakes

substantial capital investments in support of Ontario's energy needs, all three of the Company's rating agencies' have identified increasing pressure on the current credit ratings as a risk (Ex. A2-3-1).

In addition to debt financing, the Company is implementing the following financing sources:

Concurrent Cost Recovery: As described in Ex. I1-1-3, a new regulatory framework set out in Ontario Regulation 53/05 allows OPG to recover interest amounts associated with the PRP and the DNNP prior to the assets being placed in-service. This will provide OPG with an additional source of funding during the IR term. Additionally, by removing the interest that would otherwise be capitalized to the projects during construction from in-service rate base, CCR will reduce the total costs recoverable from ratepayers over the operating life of the assets.

Shareholder Equity Injection: The Plan reflects an expected shareholder equity injection in the Company, totalling $5 billion over the 2025-2027 period, which will reduce OPG's borrowing requirements.

DNNP Equity Partnership through DNNP LP (Ex. A1-4-4): The Plan reflects OPG's announced equity partnership with Canada Growth Fund and Building Ontario Fund as minority investors in the DNNP, which, subject to satisfaction of conditions, is expected to contribute approximately $3 billion of funding.

Proposed Deemed Capital Structure for OPG: OPG is proposing to apply a deemed capital structure of 52% equity and 48% debt, for its prescribed assets for the IR term. This proposal is supported by the findings of the Common Equity Ratio Study carried out by Concentric Energy Advisors (Ex. C1-1-1, Attachment 1), which concludes that there is a material increase in OPG's business risks related to the execution of major projects including the PRP, 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%.

CEITCs: In November 2025, the federal government reissued draft legislation to provide a 15% refundable CEITC with respect to investments in certain clean electricity property, including nuclear energy equipment and hydroelectric systems. The impact of the CEITCs is not reflected in this Application since this legislation has not been adopted at the time of filing. If the legislation is enacted, OPG will account for the CEITCs as a reduction in the capital costs of the underlying projects, and the Application proposes to return to customers the revenue requirement of the CEITCs through a series of variance accounts. CEITCs are discussed further in Ex. F4-2-1, Section 3.6.1.

3.4 Indigenous Relations

OPG is committed to continue to build mutually beneficial working relations with Indigenous communities proximate to its current and planned future operations through proactive engagement, consultation, fostering opportunity, and other efforts. OPG believes in establishing and maintaining these relationships through dialogue founded in respect and aimed at preserving openness, transparency, and trust. These strong relationships and partnerships are important to maintaining OPG's social licence in the communities.

OPG's Reconciliation Action Plan is a core element of its corporate strategy. The plan is grounded in the principles of the Truth and Reconciliation Commission's Calls to Action and the United Nations Declaration on the Rights of Indigenous Peoples. OPG's approach emphasizes building respectful relationships with Indigenous communities, increasing Indigenous economic participation, supporting education and capacity building, and promoting both cultural awareness and environmental stewardship.

The Reconciliation Action Plan is fully integrated into OPG's governance framework, with executive-level and OPG Board of Directors oversight. Reconciliation objectives are

embedded in OPG's procurement processes and are considered throughout project development activities. OPG's economic and partnership initiatives help to stimulate growth and development in Indigenous communities across Ontario. OPG will continue to proactively and meaningfully engage with Indigenous communities and remains committed to creating social and economic benefits through partnership and collaboration with the First Nations.

3.5 Continuous Improvement

OPG continually seeks to improve the Company's cost performance and pursues operational efficiencies. During the Plan period, OPG intends to continue pursuing performance and cost improvements through a range of initiatives including the following:

3.5.1 Digital Technology

OPG's digital technology strategy is based on the critical importance of maintaining the reliability, security, and performance of the Company's core systems while providing flexibility to respond to emerging risks and opportunities over the IR term. OPG aims to enhance project management systems and processes through automation and optimization, including standardization of digital tools, centralization of data architecture, knowledge management through artificial intelligence, and enhancing reporting capability. This strategy seeks to reduce system obsolescence risks, enhance cybersecurity, and pursue efficiencies in the Company's workflows. Digital technology initiatives are discussed further in Ex. D3-1-1.

3.5.2 Nuclear Outage Improvement Opportunities

OPG seeks to improve planned outages on refurbished units by optimizing and reducing scope, streamlining workflows and processes, and leveraging innovation, technology, industry experience and resource strategies with a view to optimize outage schedules, where possible. Details of OPG's nuclear production performance and forecasts are provided in Ex. E2-1-1.

3.5.3 Supply Chain

OPG will continue to build on existing supplier relationship management, onboarding and capability, materials management, and warehouse efficiencies as well as upgrade its core enterprise resource planning system with the expectation of greater effectiveness across

supply chain processes. These improvements will strengthen OPG's ability to deliver large-scale projects, supporting timely access to specialized materials and helping to mitigate supply chain volatility risks. OPG's procurement process is set out in Ex. F3-3-1.

3.6 Nuclear Liabilities

OPG recognizes the importance of the safe and effective stewardship over nuclear waste and planning for the eventual decommissioning of its nuclear facilities. During the IR term, OPG will complete the placement of the permanently shut down Pickering Units 1 and 4 in a safe storage state as part of a long-term decommissioning plan. The 2025-2031 Business Plan and the Application reflect the current approved 2022-2026 Ontario Nuclear Funds Agreement ("ONFA") Reference Plan.[16] The 2027-2031 ONFA Reference Plan is currently under development and is expected to be finalized in late 2026 for the Province's subsequent approval.[17] OPG's nuclear liabilities and the ONFA are discussed further in Ex. C2-1-1.

As the DNNP site owner, OPG will be responsible for the nuclear waste management and decommissioning obligations arising from the DNNP facilities. OPG has not yet fully developed the cost estimates for these future liabilities, and the Application does not propose to include such future costs in the proposed IR term revenue requirements. Pursuant to O. Reg. 53/05 that requires OPG to recover its nuclear liabilities costs with respect to the DNNP facilities (on the basis they are recorded on OPG's financial statements), the Application requests the establishment of a deferral and variance account to capture these costs. The Application does not reflect these costs in the proposed IR term nuclear revenue requirements.

4.0 BUSINESS PLANNING PROCESS

4.1 Planning Approach

The OPG Board of Directors'-approved 2025-2031 Business Plan sets out OPG's operational, financial, and other performance goals and targets for the 2025-2031 period and a current

[16] This is the same ONFA Reference Plan that was reflected in the EB-2020-0290 Payment Amounts Order.
[17] The corresponding revenue requirement impact of the approved 2027-2031 Reference Plan will be recorded in the Nuclear Liability Deferral Account for OPG's prescribed facilities and the Bruce Lease Net Revenues Variance Account for the Bruce facilities.

forecast of performance for the 2025 year based on year-to-date information.[18] The approved Plan was submitted for concurrence to OPG's shareholder on December 5th, 2025, pursuant to the Memorandum of Agreement (Ex. A1-4-1, Attachment 3).

In line with the period covered in this Application, the 2025-2031 Business Plan spans a total of seven years. For each year of the Plan, OPG prepared detailed plans for generation performance, resource requirements, asset lifecycle investments, major project execution, and operational costing for OPG's nuclear and regulated hydroelectric facilities, and DNNP facilities. OPG followed the same approach and rigour as applied to its previous seven-year plan filed in EB-2020-0290. This includes company-wide planning instructions, top-down target setting for key resource envelopes, application of consistent assumptions, and identification of risks and mitigation measures.[19]

OPG's business planning process is underpinned by the following four business imperatives, around which the 2025-2031 Business Plan is organized:

4.1.1 Operational Excellence

Continuing to safely and efficiently operate and maintain the generation fleet through a high performing, engaged workforce is OPG's core priority.

4.1.2 Project Excellence

In addition to major refurbishments and redevelopments, OPG strives to deliver all projects safely, on time, on budget, and with the required quality.

4.1.3 Financial Strength

OPG seeks to ensure a consistent level of strong financial performance that delivers an appropriate level of return on the shareholder's investment, while prudently managing risks.

[18] When presenting IR term information in this Application that requires direct continuity of balances from 2025, such as rate base values, OPG has used the 2025 current forecast information from the 2025-2031 Business Plan, rather than the 2025 budget.

[19] The key assumptions and risks associated with the 2025-2031 Business Plan are set out in Attachment 1, pp. 30-32.

4.1.4 Social Licence

Maintaining public trust, building relationships with communities, and upholding high standards of corporate citizenship is essential to OPG's ongoing social licence. This includes stakeholder expectations related to impacts on the cost of electricity and reduction of carbon emissions.

4.2 Business Plan Process

As in prior payment amounts applications, OPG's business planning and budgeting process continues to be a decentralized annual process undertaken within a consistent, top-down framework of strategic objectives, resource guidelines, and costing assumptions. Within this framework, the individual businesses and support groups develop their specific strategic and performance objectives and then identify and plan the work required to achieve these objectives.

Using the above approach, OPG issued corporate-wide business planning instructions including assumptions, schedule, and information requirements ("Instructions") for the preparation of the 2025-2031 Business Plan in February 2025.[20] The Instructions provided guidance to lines of business and functions across the organization on the preparation of planning submissions for 2025-2031. The Instructions are filed as Attachment 2 in this exhibit.

In addition to setting out resource targets, the key elements of the Instructions included:

- A summary of the strategic planning context and goals.
- Identification of key operating, project, economic, staffing, and other planning assumptions to be used in the development and costing of plans.
- A comprehensive schedule with key milestones and activities.
- Establishment and communication of information submission requirements and instructions for use of internal business planning tools.

[20] OPG's corporate business planning process is coordinated by the Finance organization. OPG's 2026-2031 Targets are provided in Attachment 3 to this schedule.

Based on the key planning assumptions, the Instructions provided annual OM&A and sustaining capital expenditure targets for the Business Plan period. The OM&A targets were determined with a view to establish the baseline cost structure reflecting the unique operating condition of Pickering during the multi-year four-unit refurbishment outage. These targets were set to ensure Pickering's readiness to return to service, support major project commitments, and promote ongoing safe and reliable operations across the fleet. Sustaining project capital targets were set in recognition of the condition of the assets and with the objective to maintain asset availability and reliability over the long term, taking into consideration resourcing capacity and need.

Based on the Instructions, each business and function identified objectives, performance targets, resources, key initiatives, and risk mitigation strategies that informed the development of their business plan input. This included work programs and projects required to achieve the objectives, taking into account the corporate targets. Where necessary, trade-offs and adjustments were made to deal with emerging issues. Reviews were undertaken within each of the businesses and functions such that the resulting plans reflected the work needed to meet the applicable safety and social licence goals, regulatory commitments, operational targets, project milestones, and strategic objectives. Project portfolios of both OM&A and capital investments, maintained and prioritized within each business, allowed the highest priority investments to be incorporated into the business planning submissions.[21] Nuclear and hydroelectric generation plans were developed based on outage requirements, reliability parameters, water flow forecasts, and other applicable variables.

Through the spring of 2025, OPG held a series of review meetings with the senior leaders of each business function on their respective plans. Additionally, briefings and challenge sessions were held on business and functional plans with senior leaders of the Finance team, including reviews of planning submissions against targets and strategic objectives.

[21] OPG's enterprise-wide investment identification and project management processes are set out in Ex. D2-1-1.

Most business units met their OM&A targets (Base, Outage and Project OM&A) as set out in Attachment 3, except for the Digital and Technology Services ("DTS") group due to higher than anticipated software costs (Base OM&A) and higher project costs for the Enterprise System Modernization Projects (Project OM&A). As discussed in Ex. F3-1-1 and Ex. D3-1-1, there has been notable historical inflationary increase in software costs of approximately 92% since 2020. Although this increase in software costs was not contemplated when setting the applicable target, inclusion of these costs into the DTS business plan will ensure that DTS can continue its focus on addressing obsolescence risks and supporting upgrades for key enterprise systems (Project OM&A).

Overall, business unit sustaining capital expenditures were in aggregate within target over the period, with the exception of the Darlington Turbine Rotor Replacement project. This project was in the early stages of planning at the time the targets were developed, and since then has progressed a Business Case Summary as filed in Ex. D2-1-3 Attachment 1. While there was variability in sustaining capital expenditures across various organizations, the overall portfolio was largely balanced outside of the non-portfolio project above.

Based on submissions received from across the organization and any subsequent revisions through the review process above, a consolidated generation and financial plan was prepared. The information in the planning submissions was supplemented by corporate-level financial inputs including depreciation expense, nuclear liabilities impacts, borrowing requirements, income taxes, and deferral and variance account additions for the remaining years of the current IR term.

The consolidated Business Plan was then reviewed with the President and Chief Executive Officer, Chief Financial Officer, and other members of the Enterprise Leadership Team, and the final consolidated Business Plan was submitted to and subsequently approved by the OPG Board and submitted to OPG's shareholder on December 5, 2025.

5.0 OVERVIEW OF COMMUNITY ENGAGEMENT

This section reviews the various ways in which OPG typically engages with the individuals, businesses, and institutions that consume electricity in Ontario and considers customers when planning work and operating its generating facilities. OPG has always considered customers' interests in business planning, and the interests of the communities in which the Company's facilities are located. As described in this section, OPG engages with customers when planning projects, making operational decisions, and participating in communities.

This schedule summarizes the various forms of customer engagement that OPG conducts during the course of its normal business operations, divided into three broad categories, each of which is discussed separately in this schedule:

1. Community Partnerships;
2. Indigenous Community Relations; and
3. Public Information and Safety Programs.

5.1 Community Partnerships

This section describes how OPG works with communities to help ensure that the Company's projects are planned and executed in a manner that reflects the preferences of local communities, and that its operations minimally affect local communities. OPG considers and accommodates community feedback in various aspects of its regular operations, including the Company's ongoing Nuclear Community Advisory Councils, community leader engagement, Waterway Coordination programs, Project Planning and Execution, and Academic Collaboration. Each form of community partnership is discussed below.

5.1.1 Community Leader Engagement

OPG generally engages with local leaders in communities where the Company's generating facilities are located. Engaging with community leaders helps OPG ensure that it has a clear, unbiased perspective on the issues that matter to major segments of the local community.

For the Renewable Generation facilities, this includes regularly scheduled outreach and update meetings with elected officials to keep leaders up to date on operations, growth plans, and safety.

In the nuclear site communities, OPG identifies local leaders in government, business, academic, and other sectors that reflect a spectrum of views on the company's role in the community. Discussions may cover a number of topics, ranging from safety and environmental issues to upcoming Company projects at local facilities.
Being qualitative in nature, engagement with community leaders provides directional indication of community views from informed individuals from a spectrum of sectors and interests. OPG's senior management is able to draw upon these views when making business decisions.

5.1.2 Project Planning and Execution

OPG's projects are often significant endeavours that have the potential to affect local communities in a number of ways. These impacts range from practical impacts during construction, to driving economic growth.

OPG's projects require significant logistical coordination in host communities, such as altering traffic flows or requiring safety-related restrictions on access to areas of land and waterways. Projects often require an influx of personnel, either on a temporary or permanent basis. OPG also takes measures to mitigate risk to a community's environment, archeological record, or heritage sites.

In order to address these various potential effects, OPG consults with host communities throughout the planning and execution of projects. The elements and scale of a project-specific consultation depend on the nature of the project and its potential to affect the local community. The appropriate form and the extent of community engagement activities will also depend on the circumstances of a given project.

For example, when OPG plans to carry out sustaining capital work at a generating station, the Company assesses the potential for the project to affect the local community and identifies

what forms of consultation and information sharing may be required. Each project is different, and OPG makes these assessments on a case-by-case basis.

For larger projects, OPG's community outreach can be quite broad, including town hall meetings to discuss potential impacts and solicit customer input. The specific forms of outreach vary with the nature of the project, its location, and other factors. Where possible, community feedback will be taken into account and reflected in the project plan. OPG also makes use of dedicated websites for major projects, providing information and soliciting input from the widest possible audience.

Not all projects require dedicated consultations; it would not be efficient or cost effective for OPG to hold town hall meetings for smaller projects that occur exclusively within OPG's facilities and have no material impact on the community. When OPG identifies a potential community impact in connection with a smaller project, such as road closures, it takes appropriate measures to inform local residents and businesses. As part of this process, OPG provides contact information for individuals or organizations who may have questions or concerns.

5.1.3 Nuclear Community Advisory Councils

OPG's nuclear generating stations have a significant role to play in the Clarington and Pickering communities. OPG strives to understand host communities' priorities and to be transparent in providing residents with information about the Company's nuclear facilities. To that end, OPG has established Community Advisory Councils ("CAC") for both the Darlington and Pickering generating stations.

The Nuclear CACs were established in the 1990s and are comprised of members from a large number of sectors from across the community. CAC membership includes community associations, municipal government, health, environment, education, youth, business, and members at large. CAC members live or work in the vicinity of the plants and serve on a voluntary basis.

The CACs meet between six and eight times per year. During those meetings, the members receive briefings from OPG staff and other experts. Although meetings focus on environment, public health, safety, and economic issues, the topics vary depending on the issues of interest to the community. CAC members have opportunities to ask questions about OPG operations and projects, and to discuss what they have heard.

The CACs are an important bridge between OPG and the communities where the Company's nuclear generating stations are located. It allows OPG's senior management to hear directly from members of the community, giving the community a direct connection to the Company and allowing the Company to better understand and respond to community questions, concerns, and preferences.

5.1.4 Waterway Coordination

OPG's hydroelectric facilities rely on the same waterways that many Ontarians live near, and rely on for their water supply, work and leisure. OPG operates its hydroelectric generating facilities in coordination with communities and governmental agencies to support public safety during high water events, emergencies and in the course of normal operations. For many rivers, water management plans have been established to account for the needs of the various groups that use and rely on the river. OPG also modifies some of its operations at hydroelectric generating stations to accommodate other users of Ontario's waterways both on an on-going basis and for special circumstances.

OPG coordinates its use of Ontario waterways with organizations and government bodies including the Ontario Ministry of Natural Resources, local conservation authorities, local municipalities, Indigenous communities, the Federal Department of Fisheries and Oceans, and Parks Canada.

In times of extreme watershed conditions, OPG may be able to play a moderating role. When there is potential for flooding, OPG helps to manage the release of water to mitigate risks to local communities (both up-stream and down-stream from the Company's generating facility, depending on the location of the flood risk). Similarly, OPG may be called upon during periods

of drought to support conservation efforts and aquatic habitat. OPG also maintains an extensive Waterway Public Safety Program to mitigate public safety risks associated with the Company's facilities.

5.1.5 Academic Collaboration

OPG works with academic and other industry partners to research and promote public safety in connection with electricity generation. By collaborating and sharing information with these parties, OPG is able to promote public benefits, like flood prevention and innovation, and reduce costs for researchers.

As an example, OPG has collaborated with Natural Sciences and Engineering Research Council of Canada via FloodNet, a multi-disciplinary research network that is partly funded by Natural Sciences and Engineering Research Council of Canada. FloodNet allows efficient coordination between stakeholders, connecting researchers from across Canada and pooling data from OPG and other industry and government partners. FloodNet is then able to develop enhanced flood forecast tools and flood management capacity, which ultimately reduce the damage, socio-economic impacts, and human distress caused by flooding, and help protect community water systems and the environment.

5.2 Indigenous Community Relations

OPG is committed to building and fostering mutually beneficial working relationships with Indigenous communities near its current and planned future operations. These relationships are built on a foundation of respect for the culture and customs of Indigenous peoples and established and maintained through ongoing dialogue aimed at preserving openness, transparency and trust.

Where appropriate, OPG pursues prospective generation-related developments with Indigenous communities that can provide the basis for long-term, mutually beneficial, commercial arrangements.

OPG's commitment to engagement and consultation has been beneficial to both the Company and to Indigenous communities. By working to resolve grievances and to build relationships, OPG believes that future projects and continued operation will be able to proceed more efficiently and deliver the best outcomes for Indigenous communities, customers, and the Company.

5.3 Emergency Management and Public Safety Programs

Public safety around its facilities is important to OPG. In addition to the community engagement processes described above, OPG keeps the general public informed about and prepared for emergencies and other safety-related issues through several programs.

- Each of OPG's regions has Dam Safety Emergency Preparedness and Response Plans in place. These plans are maintained in consultation with community stakeholders (e.g., first responders, mayors' offices, Indigenous Communities, fire services, and other emergency organizations). OPG meets regularly with these stakeholders to review the emergency plans and to facilitate alignment with the stakeholders' processes. OPG also engages with these stakeholders in the development and execution of dam safety exercises, involving simulated emergencies which provide an opportunity to test the emergency plans and communication channels, and to solidify the training of our staff.
- Public safety around OPG's dams and hydroelectric generating facilities is managed through a dedicated program that includes a number of components such as the installation of physical safety control measures (e.g., signage, fences, booms, and buoys), and a proactive regional public safety around dams communications plan.
- OPG regionalizes its safety signage to help effectively communicate safety hazards in local communities in languages that are most relevant within those communities.
- OPG conducts regular emergency and preparedness response exercises at both Darlington and Pickering facilities. The exercises provide opportunities to validate the interoperability of emergency response plans and processes currently in place for OPG and participating organizations from all levels of governments.

LIST OF ATTACHMENTS

Attachment 1:	2025-2031 Business Plan
Attachment 2:	2025-2031 Business Planning Schedule and Assumptions
	(“Instructions”)
Attachment 3:	OPG Business Plan Targets

OPG Confidential Exclusive

ONTARIO POWER GENERATION

November 13, 2025

2025-2031 Ontario Power Generation Inc. Business Plan

This document is Ontario Power Generation's (OPG or the Company) 2025-2031 business plan, which sets out performance goals, targets and resource allocations for the 2025-2031 period as well as a forecast of performance for the 2025 year. The business plan will be submitted to OPG's Shareholder, the Province of Ontario (Province), for review and concurrence in accordance with the Memorandum of Agreement between the Shareholder and OPG.

Executive Summary

The 2025-2031 business plan anchors OPG's commitment to make major investments in its existing and new generation assets to ensure they are available to safely, reliably and cost effectively meet the needs of electricity consumers and support economic growth over the near and longer term. The plan is aligned to the Province's Integrated Energy Plan (IEP) and energy security objectives, and is responsive to the Independent Electricity System Operator's (IESO) forecast of Ontario's electricity demand growing by 75% through 2050. It reflects OPG's commitment to strong levels of operational performance and cost effectiveness, to the benefit of ratepayers, and is underpinned by the Company's commercial mandate to deliver value to the Shareholder. OPG will advance these priorities while continuing to embed a strong safety culture and effectively managing the organization through this period of change.

The plan includes the final two years of the 2022-2026 Ontario Energy Board (OEB) rate-setting period for the Company's regulated nuclear operations and of the current legislated rate freeze for the Company's regulated hydroelectric operations. It also encompasses the 2027-2031 period and will underpin OPG's upcoming rate application to the OEB covering such five-year rate term, planned for submission in late 2025. The outcomes of this application will set updated prices for the majority of OPG's electricity through a public and transparent process, shaping the financial performance of the Company's regulated business and OPG's overall financial position.

With a number of key priorities, this business plan is the largest planning undertaking in OPG's history. During this period, the Company commits to concurrently undertake a number of major investments in development and refurbishment projects critical to meeting Ontario's electricity needs, including: the completion of the Darlington Nuclear Generating Station (Darlington) Refurbishment project by 2026 (Darlington Refurbishment), the continued operation of the Pickering Nuclear Generating Station (Pickering) Units 5-8 into 2026 before transitioning to refurbishment beginning in 2027 (Pickering Refurbishment) subject to the Province's approval, the execution of the Darlington New Nuclear Project (DNNP) with the goal of connecting the first small modular reactor (SMR) to the grid by the end of 2030, significant hydroelectric fleet investments to ensure continued reliable operations, planning for new nuclear and hydroelectric generation options, [redacted], all while continuing to safely, reliably and cost effectively operate the existing facilities.

With these generational investments in OPG's fleet, the plan marks a significant shift from the previous seven-year planning period (for years 2020 to 2026) that focused on managing the then-upcoming downsizing of the Company as a result of the anticipated shutdown of Pickering. Looking forward, OPG is focused on ensuring that its operations, projects, workforce and financial strategies and resources are aligned to successfully deliver on the Company's commitments for the next seven years and enable its continued future growth potential.

Highlights of the 2025-2031 business plan include:

Over the seven-year period, net income attributable to the Shareholder averages approximately [redacted] in 2031 as major nuclear and regulated hydroelectric capital investments are completed and enter the regulated rate base. This level of earnings will enable OPG to deliver a Total Shareholder Return[1] of [redacted] per year, on average, reaching [redacted] by 2031, [redacted]. As additional capital is deployed, earnings and Total Shareholder Return are expected to [redacted]

As the regulated facilities generate the majority of OPG's revenues and operating cash flows, the Company's financial strength and ability to cost-effectively finance its continued investment in the electricity system will depend significantly on the upcoming rate application to the OEB, which will set OPG's nuclear and hydroelectric regulated rates for 2027-2031. It is necessary for OPG to secure timely regulated rates that, while taking into account the impact on electricity consumers, are sufficient to support the Company's capacity to execute on its projects that will help meet growing electricity demand and advance government policy objectives. The requested rates for the nuclear facilities are expected to include the first in-service units of both the DNNP and the planned Pickering Refurbishment during this period. For the hydroelectric facilities, this will be the first cost-based rebasing of the regulated rates in over a decade. Based on current assumptions, the rate application is expected to result in a requested annual increase of up to 2.5%, or $3.50, each year, on average, for a typical residential customer's monthly bill. The new regulated rates are assumed to be effective January 1, 2027.

OPG is embarking on a transformational capital investment program with this business plan. With [redacted] in capital investments planned during the period, the Company is working to advance and bring into service a number of key development and sustaining projects to meet the forecasted electricity demand in the province. In doing so, OPG remains committed to project excellence and will leverage its success with the Darlington Refurbishment and other recent projects.

<u>OPG Corporate Investments</u>

- Completing the Darlington Refurbishment in the first half of 2026 ahead of the original schedule and expected to be under the approved budget
- Completing the Pickering Refurbishment definition phase in 2026 and, subject to the Province's approval, transitioning the project to execution, based on the budget and schedule to be approved by the Board. The first unit, Unit 5, is anticipated to return to service in the second quarter of 2031 and all four units by 2034, with capital expenditures of approximately $20 billion over the business plan period
- Bringing into service the first small modular reactor unit of the DNNP in the fourth quarter of 2030 (DNNP Unit 1), the first of its kind in the G7, based on the budget and schedule approved by the Board. The total capital investments for DNNP, inclusive of progressing the three subsequent units subject to requisite approvals, are approximately $13 billion over the business plan period
- Continuing to undertake comprehensive refurbishments and select redevelopments across the Ontario-based hydroelectric fleet, with approximately [redacted] in capital expenditures over the business plan period
- Executing expanded sustaining capital programs to renew and ensure continued strong performance of the generating fleet in support of a reliable electricity system, including restarting the Pickering sustaining project portfolio. OPG will also refresh major digital technology systems according to their lifecycle as well as invest in technology enhancements to support operations needs and project delivery
- Continuing to pursue potential new generation options in alignment with the Province's vision for Ontario's energy needs, including the announced early initiation and engagement efforts for new large nuclear generation at OPG's Wesleyville site and co-planning for greenfield hydroelectric opportunities in the Moose River Basin with the Taykwa Tagamou Nation and Moose Cree First Nation. OPG remains committed to working with Indigenous communities to create social and economic benefits through partnership and collaboration, including pursuing commercial partnerships on new energy investments. The plan includes non-capital funding for potential new generation development but does not include any subsequent capital expenditures or associated resources that would be required should a decision be made to proceed with these projects

[1] In addition to net income, Total Shareholder Return includes income tax, hydroelectric gross revenue charge and property tax amounts payable to the Province.

Subsidiary Investments

- Atura bringing into service the previously awarded 405 MW natural gas plant expansion and 250 MW grid-scale battery energy storage system (BESS) at the Napanee generating station site during the business plan period, along with capacity upgrades at existing combined cycle gas facilities and the low-carbon hydrogen facility in Niagara Falls
- Atura participating in the IESO's upcoming initial Long Term 2 Request for Proposal (LT2 RFP) window in December 2025, [redacted]
- Laurentis Energy Partners (LEP) expanding medical isotope production through construction of a second Target Delivery System (TDS) to be installed at Darlington Unit 3, with commercial production of isotopes expected from both the first and second TDS at Darlington [redacted] subject to health regulatory approvals

In October 2025, OPG entered into an agreement to sell its wholly-owned subsidiary in the United States, Eagle Creek Renewable Energy (Eagle Creek), with the transaction expected to close in the first quarter of 2026, subject to customary closing conditions. The plan reflects anticipated net proceeds from the transaction of approximately CAD [redacted], which will support funding needs of the Company's capital investment program.

OPG plans to generate approximately [redacted] of energy from its Ontario-based facilities over the business plan period. Most of the nuclear generation is expected from the refurbished Darlington units (167 TWh), inclusive of an outage plan that accommodates a station-wide vacuum building outage (VBO) in 2027 and turbine rotor replacement and other work across the units to support reliable post-refurbishment operations. Regulated hydroelectric generation is expected to provide 223 TWh, supported by increased levels of capital investment to renew the approximately 90-year old fleet for future decades. [redacted] Pickering Units 5-8 are anticipated to come offline at the end of September 2026 before transitioning to refurbishment.

The plan reflects the successful selection of OPG's Lennox Generating Station (Lennox) under the IESO's Medium-Term 2 procurement as announced in May 2025, securing a new five-year contract effective May 1, 2029 for the province's largest non-nuclear generating asset, and the current contract term for the Atikokan Generating Station (Atikokan) expiring in July 2029.

The annual operating cash flow over the business plan period [redacted] from nearly [redacted] This includes an assumed new regulatory mechanism for concurrent cost recovery (CCR) of debt financing costs during the construction of the DNNP and the Pickering Refurbishment, in alignment with a proposed amendment to O. Reg. 53/05 to that effect published by the Province in May 2025. The mechanism would provide OPG an additional source of funding and strengthen OPG's ability to cost effectively deliver these projects to the benefit of ratepayers, in addition to substantially reducing the total costs to ratepayers over the operating life of the assets by removing the construction period debt financing costs from in-service rate base. Accordingly, such capital expenditures and in-service amounts would not include capitalized interest and are shown in the plan on that basis, unless otherwise noted.

In addition to operating cash flow inclusive of CCR, OPG's capital needs are assumed to be supported through a shareholder equity injection from the Province, totaling $5 billion over the 2025-2027 period. Equity injections directly reduce OPG's borrowing requirements and benefit ratepayers by helping to ensure cost effective financing for the Company's investments in the electricity system. Under the anticipated terms of the equity injection, associated dividends would be in-kind during the business plan period.

The plan reflects federal clean energy investment tax credits (ITCs) to the extent they have been legislated into law at the time of writing and therefore does not include the Clean Electricity Investment Tax Credit (CEITC) which has been reintroduced by the Federal Government in November 2025. If it is legislated, OPG would be eligible for the CEITC as a federally-tax exempt entity, reducing OPG's forecasted financing requirements and ratepayer costs. OPG's upcoming rate application to the OEB will propose a mechanism to pass to customers the revenue requirement benefit of CEITCs should they be ultimately available for the Company's regulated facilities.

The plan reflects OPG's recently announced equity partnership with the Canada Growth Fund (CGF) and Building Ontario Fund (BOF) as non-controlling investors in the DNNP. The newly created partnership will lease the assets from OPG, who will continue to be the Canadian Nuclear Safety Commission (CNSC) licence holder, project manager and operator of the facility. The transaction is assumed to close by the end of 2025, subject to certain conditions including enablement of the partnership as a new rate regulated entity consistent with a proposed amendment to O. Reg. 53/05 published by the Province in May 2025. In parallel, OPG continues to engage with participating Williams Treaty First Nations on the terms of their potential commercial participation in relation to the DNNP equity partnership. Supported by both the Provincial and Federal Governments, the partnership will reduce OPG's borrowing requirements and will help to further catalyze the importance of DNNP to Ontario and Canada's nuclear energy leadership, while providing opportunities for local First Nations to benefit from a new project in their territory.

Driven predominantly by the anticipated parallel execution of the DNNP and the Pickering Refurbishment and before considering CEITCs, the Company's total debt is forecasted [redacted] from [redacted] based on the assumptions in the plan. Further borrowing requirements may arise in support of new nuclear or hydroelectric generation projects, if approved to proceed. As future borrowing needs may exceed the estimated annual issuance capacity in the Canadian market, OPG has been examining bond markets outside of Canada to ensure sufficient access to necessary financing and is currently focused on expanding the bond program into US markets by becoming an SEC registrant as a Foreign Private Issuer, subject to the Board's approval.

As OPG undertakes substantial capital investments, rating agencies have identified increasing pressure on OPG's credit metrics as a risk. However, while they are projected to decrease, key credit metrics are [redacted] Moody's Investors Service (Moody's) and S&P Global Ratings (S&P) thresholds for the current ratings, based on business plan assumptions. The metrics would further benefit from the availability of the CEITC. With such outcomes, OPG's strategy in managing the credit ratings will emphasize qualitative factors, including the continued support from the Province as would be further evidenced by the implementation of CCR and the shareholder equity injections, and the Company's continued operational and project excellence. OPG will continue to pursue available credit supportive funding sources with a view to manage borrowing requirements and support credit metrics, and believes that the current credit ratings can be maintained for the duration of the plan.

Over 90% of OPG's nuclear and hydroelectric procurement is sourced from Canadian suppliers, supporting government priorities around domestic energy security and economic investment. While OPG's domestic procurement strategy mitigates the direct impacts of the current tariffs and trade uncertainty, the ongoing instability of the trade-related landscape and the broader economic and geopolitical uncertainty could affect the Company's cost structure, supply chains and project delivery. These potential impacts are inherently unknown and not considered in the plan. OPG will continue to monitor and evaluate these developments, including through enhanced supply chain monitoring, stakeholder engagement and assessment of procurement diversification options. The Company will also continue to monitor and manage the foreign exchange risk as appropriate, recognizing that continued volatility is possible for the foreseeable future.

OPG's resourcing and operating cost plans reflect the evolution of an organization that was previously planning for a significant downsizing to one entering a period of growth and renewal. While employees are planned to transition between generating facilities and major projects based on resourcing needs, OPG's overall workforce is expected to remain largely steady over the business plan period. This reflects a realignment of the workforce strategy in view of the Company's increasing resourcing needs and labour market conditions driven by project activity, enabled by a focus on labour deployment flexibility in negotiated labour agreements. In addition to mitigating project resourcing risks, this strategy will support the ability to retain key skillsets and expertise in order to manage talent availability, attraction and training risks to future operations.

The operating cost profile over the period generally follows the anticipated movement of employees between generating facilities and major projects, and by 2031, reflects DNNP Unit 1 and refurbished Pickering Unit 5 coming online. For both of these assets, the forecasted operating costs in 2031 are impacted by relative diseconomies of scale due to the respective fixed costs required to operate a single unit at each facility. During the Pickering Refurbishment period, operating costs will continue to fund the necessary operations and oversight processes, at the station and within support functions, that remain applicable to Pickering during a refurbishment outage, including inspection, maintenance and other activities required to maintain the units and ensure readiness to return to service. Within these cost

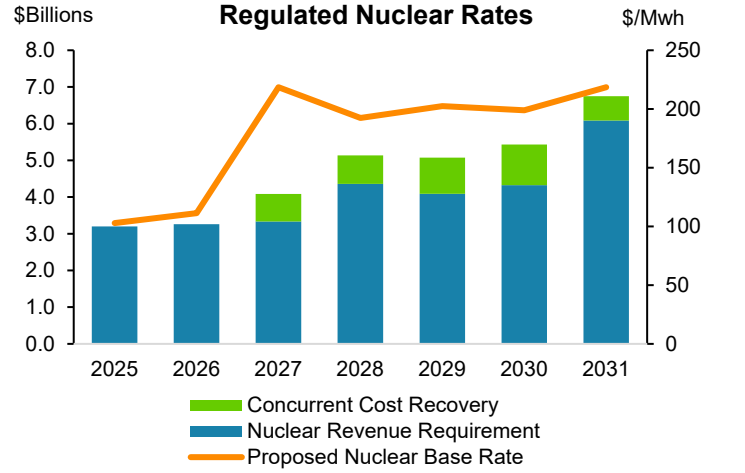
structures, the Company will continue to identify and pursue opportunities for operational improvement and efficiencies.

The plan reflects the current reference plan under the Ontario Nuclear Funds Agreement (ONFA), covering the 2022-2026 period, as previously approved by the Province. The segregated funds established under the ONFA are used to satisfy OPG's financial guarantee requirements under the CNSC operating licences for the existing facilities. The ONFA reference plan update process for the 2027-2031 period is underway and will be incorporated into future business plans. The updated reference plan will be subject to the Province's review and approval. OPG is also evaluating how it could satisfy the financial guarantee requirements that would apply under a future DNNP operating licence issued by the CNSC, including developing detailed estimates of the decommissioning and waste management liabilities expected as a result of DNNP operations. The resulting impacts will be included in future business plans and are assumed to be subject to a regulatory deferral account.

Key planning assumptions are found in **Appendix 1**. A listing of key risks is included in **Appendix 2**. **Appendix 3** and **Appendix 4** set out the detailed financial, headcount and operational targets and forecasts. **Appendix 5** includes the Environmental, Governance and Sustainability Overview.

Regulated Rates

OPG plans to submit a five-year nuclear and hydroelectric rate application to the OEB for the 2027-2031 period in late 2025 and continues to develop the specific associated rate-setting proposals. OPG will request the new rates to be effective January 1, 2027.



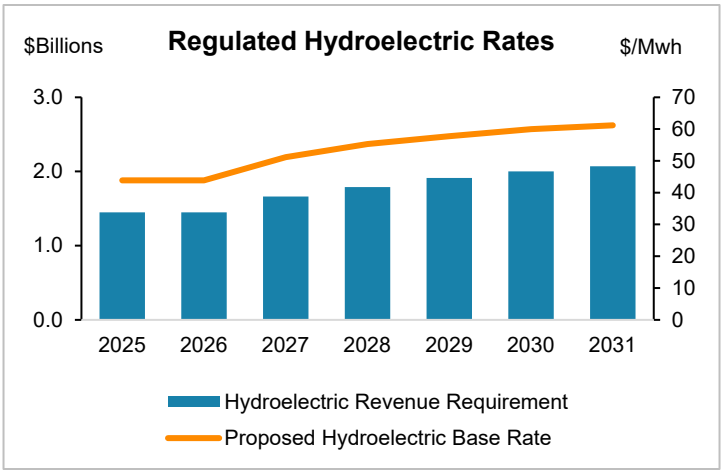
The higher nuclear regulated rate in 2027 reflects a temporary decrease in Darlington generation as a result of a unique combination of planned outages in that year, including the four-unit vacuum building outage.

For the nuclear business, the rate application will seek approval of nuclear base regulated rates based on the custom incentive rate-setting framework previously approved by the OEB for OPG's nuclear assets. This framework determines each year's base regulated rate using annual revenue requirements net of an applicable efficiency stretch factor and individual year production forecasts. The plan reflects projected nuclear rates that include the start of commercial operation of DNNP Unit 1 in the fourth quarter of 2030 and the return to service from refurbishment of the first Pickering unit, Unit 5, in the second quarter of 2031. The plan assumes that a single base regulated rate will be in place for OPG's Pickering and Darlington facilities and the DNNP partnership, determined by blending the respective entities' annual nuclear revenue requirements and production forecasts.

The higher nuclear regulated rate projection in 2027 reflects a temporary decrease in Darlington generation as a result of a unique combination of planned outages in that year, including the four-unit vacuum building outage. In order to help manage the resulting ratepayer impact while balancing the Company's financing needs, OPG is considering deferring collection of a portion of the 2027 nuclear revenue requirement to later in the five-year rate term, inclusive of an appropriate carrying cost. OPG is seeking customer feedback on this approach.

Under the OEB's traditional rate setting framework, capital costs inclusive of accrued interest during construction are recoverable from customers once the associated assets are placed in service. In May 2025, the Province published a proposed amendment to O. Reg. 53/05 that would establish a new regulatory mechanism for recovery of debt financing costs for the DNNP and the Pickering Refurbishment concurrent with their construction. The plan assumes that such mechanism is in place by the beginning of 2026, with cost recovery beginning in 2027. This would provide OPG an additional source of funding during a period of increased capital investment needs and strengthen OPG's ability to cost effectively deliver these two large projects, to the benefit of ratepayers, by supporting the Company's overall credit

profile and current credit ratings. Additionally, by removing construction period interest costs from the in-service rate base, CCR would substantially reduce the total costs recoverable from ratepayers over the operating life of the assets.



OPG's hydroelectric base regulated rates were previously set using a price-cap index incentive rate-setting model for the 2017-2021 period, by escalating existing cost-based rates that had been set based on 2014-2015 forecasted information, and then became subject to a legislated rate freeze for the 2022-2026 period. As such, the upcoming application to the OEB will include OPG's first cost-based hydroelectric rate rebasing in over a decade. The plan reflects the 2027 hydroelectric base regulated rate being reset on a cost of service basis, with subsequent years' rates determined using a price-cap index with the addition of a custom capital factor to support the need for ongoing investments in the long-term availability and reliability of the assets.

The plan reflects continued recovery and repayment of deferral and variance account balances, most recently approved by the OEB as of the end of 2022, through nuclear and hydroelectric rate riders currently in effect to the end of 2026. The plan contemplates that most of the deferral and variance account balances as of the end of 2024 are cleared through new rate riders as part of the 2027-2031 rate application. This includes the Rate Smoothing Deferral Account prescribed by O. Reg. 53/05, which must begin to be recovered following the end of the Darlington Refurbishment. As deferral and variance accounts represent amounts recorded in prior periods, their recovery improves the Company's operating cash flow but does not have a material impact on net income over the business plan period.

The projected 2027-2031 nuclear and hydroelectric rates include generational investments that OPG is making in the province's electricity system, reflecting the Company's role in serving Ontario's electricity demand. Aligned to the Province's IEP and energy security objectives, these investments will ensure that OPG's existing and new nuclear and hydroelectric assets are available to safely, reliably and cost effectively meet the needs of consumers over the near and longer term. Based on current planning assumptions, OPG's upcoming rate application is expected to result in a requested annual increase of up to 2.5%, or $3.50, each year, on average, for a typical residential customer's monthly bill during the five-year period.

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Net Income and Total Shareholder Return

OPG aims to generate strong financial returns for the Shareholder, while taking into account the impact on electricity consumers by continuing to implement improvements in the Company's cost structure.

OPG's financial results for the 2027-2031 period will be subject to the outcome of the upcoming rate application to the OEB.

The in forecasted net income in results is largely due to:

- The return of Darlington Unit 1 from refurbishment in the fourth quarter of 2024, resulting in three Darlington units being fully operational during 2025;
- No major planned outages for Darlington in 2025, resulting in higher production and lower OM&A costs;
- The deferral of the Darlington Unit 2 turbine control and auxiliary system upgrade work to 2027 to assist with managing grid reliability and resource considerations during concurrent nuclear outages, which, in the setting of OPG's current nuclear regulated rates, was assumed to take place in 2025; and
-

The in forecasted net income in is largely due to:

- The advancement of a major Darlington Unit 3 planned outage from 2027 into 2026, relative to the schedule assumed in the setting of OPG's current nuclear regulated rates, to maintain the three-year interval for inspections given the earlier return to service of the unit from refurbishment as well as to accommodate the steam generator (SG) primary moisture separator replacements, partly offset by the expected return to service of Darlington Unit 4 from refurbishment in 2026; and
- The earnings in reflecting the deferral of the Darlington Unit 2 turbine control and auxiliary system upgrade work, as discussed above.

The in forecasted net income in reflects the anticipated rebasing of regulated rates in 2027 to reflect the current capital expenditure, operating cost and production forecasts. Net income is projected to as nuclear and regulated hydroelectric capital projects are completed and enter the regulated rate base.

OPG will return to ratepayers revenue net of costs related to the operation of Pickering Units 5-8 during the first nine months of 2026 through a regulatory variance account established under O. Reg. 53/05, subject to the OEB's review. These revenues and costs therefore do not affect planned net income. The operation of Pickering Units 5-8 during this nine-month period was not contemplated in the setting of OPG's current nuclear regulated rates.

OPG's regulated business earnings over the 2022-2026 period are projected to be largely within the thresholds prescribed under the OEB-approved earnings sharing mechanism and therefore the plan does not include an associated liability.

OPG's forecasted net income for 2025 is projected to be the budgeted amount

[redacted]

OPG's forecasted earnings and Total Shareholder Return benefit from an assumed shareholder equity injection from the Province totaling $5 billion over the 2025-2027 period (discussed further in *Financing and Liquidity*). Equity injections directly reduce OPG's borrowing requirements and benefit ratepayers by helping to ensure cost effective financing for the Company's investments in the electricity system. [redacted]

Total Shareholder Return consists of net income, income taxes to the Province, hydroelectric gross revenue charge payments, and payments in lieu (PILs) of property taxes to the Ontario Electricity Financial Corporation. It is a measure of OPG's contribution to the Province's fiscal results.

Financing and Liquidity

[redacted]

The operating cash flow in [redacted] from the operation of Pickering Units 5-8 during the first nine months of the year, as this was not contemplated in the setting of OPG's current nuclear regulated rates. However, the net income impact of this benefit will be offset by a regulatory variance account credit recorded in 2026, to be settled with ratepayers in a subsequent period. In 2029, net income [redacted] while cash flow from operations [redacted] reflecting [redacted] cash from operations in 2028 due to an assumed deferral in collection of a portion of the 2027 nuclear revenue requirement to 2028 to help manage the 2027 ratepayer impact from the upcoming rate application.

OPG's main financing sources included in the plan are operating cash flow, debt financing, shareholder equity injections from the Province and CGF and BOF's equity contributions to the DNNP partnership. Additionally, the plan reflects the expected receipt of net proceeds in the first quarter of 2026 from the recently entered transaction to sell Eagle Creek. As discussed below, only legislated federal ITCs at the time of writing are reflected in the plan. Operating cash flow reflects recovery of CCR amounts assumed in the regulated rates beginning in 2027 (discussed further in *Regulated Rates*).

Based on the assumptions in the plan, OPG's total debt is forecasted to [redacted] by approximately [redacted], from [redacted] at the end of 2025 to [redacted] in 2031. The [redacted] borrowing is predominantly driven by the anticipated parallel execution of the DNNP and the Pickering Refurbishment.

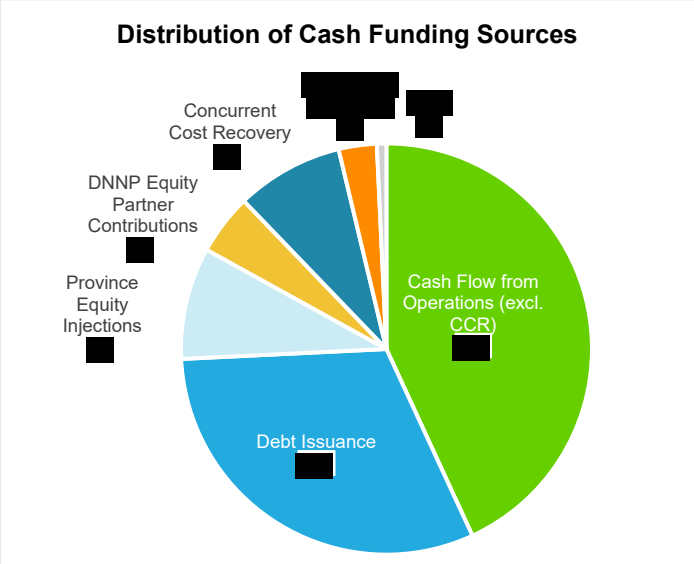
Further borrowing requirements may arise in support of new nuclear or hydroelectric generation projects, if approved to proceed.

[redacted]

OPG's sources of general long-term corporate debt include the Medium-Term Note Program, and credit facilities with the Ontario Electricity Financial Corporation and the Ontario Financing Authority. OPG expects most of the future borrowing needs to be sourced through its Medium-Term Note Program.

Historically, OPG has only accessed the Canadian bond market under the Medium-Term Note Program. As future borrowing requirements may exceed the estimated annual issuance capacity in the Canadian market, OPG has been examining bond markets outside of Canada to ensure sufficient access to necessary financing and is initially focusing on expanding the bond program into US markets by becoming an SEC registrant as a Foreign Private Issuer, subject to the Board's approval. While the cost of financing in other currencies can fluctuate relative to Canadian sourced debt based on market factors, OPG expects these impacts to be relatively modest and will seek to optimize issuance strategies to manage the costs. The assumed effective interest rate for new general long-term corporate debt is approximately 5% over the business plan period, assuming current credit ratings are maintained.

The plan assumes that the Province will make an equity injection in OPG totaling $5 billion over the 2025-2031 period, of which $1 billion is received in late 2025, [redacted] Under the anticipated terms of the equity injection, associated dividends would be in-kind during the business plan period.



The plan reflects federal ITCs to the extent they have been legislated into law at the time of writing and are applicable to the specific technology of a project. [redacted] The ITCs will be accounted for as reductions to the capital cost of the underlying eligible projects. The Company continues to monitor developments related to the previously proposed CEITC, which has been reintroduced by the Federal Government in November 2025. If legislated, the CEITC would be available to OPG as a federally tax-exempt entity, reducing OPG's forecasted financing requirements and ratepayer costs. OPG's upcoming rate application to the OEB will propose a mechanism to pass to customers the revenue requirement benefit of CEITCs should they ultimately be available for the Company's regulated facilities.

The plan reflects OPG's recently announced equity partnership with CGF and BOF as minority investors in the DNNP. Under the terms of the partnership, the project will be constructed and operated through a new rate regulated entity, which will lease the assets from OPG, with OPG as the controlling investor. OPG will also continue to be the CNSC licence holder, project manager and operator of the facility, with the partnership reimbursing OPG's costs incurred in performing these roles. As the owner of the assets, OPG will retain decommissioning and waste management liabilities for the facilities and the site. The transaction is assumed to close by the end of 2025, subject to certain conditions including enablement of the new rate regulated entity pursuant to a proposed amendment to O. Reg. 53/05 published by the Province in May 2025. In parallel, OPG continues to engage with participating Williams Treaty First

The financial results of the partnership will be consolidated in OPG's financial results and are presented on this basis in the business plan.

Credit Metrics



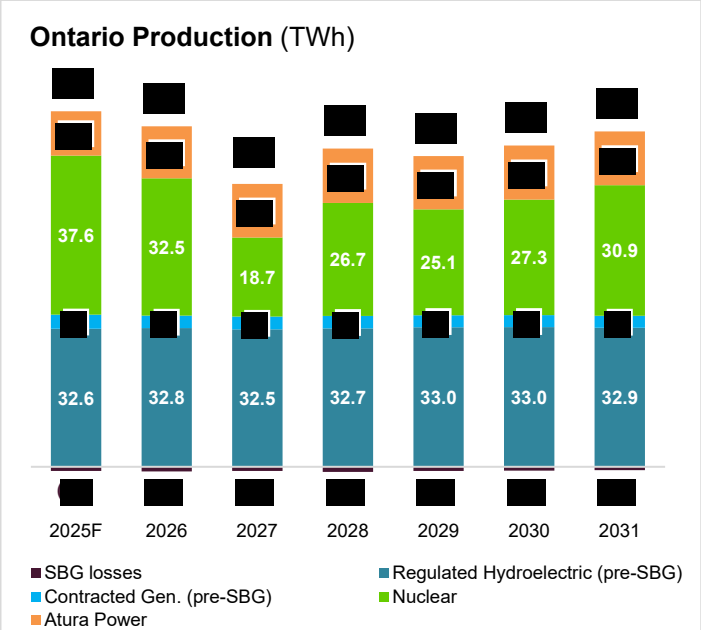
The Company closely monitors credit metrics used by rating agencies, as these metrics inform assigned credit ratings, in turn affecting the cost and availability of debt financing. Since debt represents a major source of OPG's funding, maintaining an investment-grade credit rating is essential to the Company's ability to access cost-effective financing. OPG's current long-term/short-term credit ratings are A3/P-2 from Moody's, A (low)/R-1 from Morningstar Dominion Bond Rating Service (DBRS), and BBB+/A-2 from S&P. OPG's credit ratings from S&P and Moody's benefit from a three-notch uplift from OPG's standalone credit rating, reflecting the implicit support that OPG is assumed to receive from the Province. All three rating agencies consider a potential deterioration in the relationship between the Province and OPG to be a material negative factor to OPG's credit profile that could lead to credit rating downgrades.

OPG is committed to maintaining an investment grade credit rating. As OPG undertakes substantial capital investments in support of Ontario's energy needs, all three rating agencies' reports have identified increasing pressure on the credit metrics as a risk. However, while they are projected to decrease, the [redacted] Moody's and S&P's thresholds for the current ratings, based on the business plan assumptions. The metrics would further benefit from the availability of the CEITC. With such outcomes, OPG's strategy in managing the credit ratings will emphasize qualitative factors, including the continued support from the Province as would be further evidenced by the implementation of CCR and the shareholder equity injections, and the Company's continued operational and project excellence. OPG will continue to pursue available credit supportive funding sources with a view to manage borrowing requirements and support credit metrics, and believes that the current credit ratings can be maintained for the duration of the plan.

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Ontario Electricity Generation

OPG projects total energy generation of approximately [redacted] from its Ontario-based assets over the business plan period, reflecting a continued strong focus on maximizing reliable production to meet the province's needs. Overall, the forecast reflects lower generation after Pickering Units 5-8 are taken offline in September 2026 prior to the planned refurbishment, with the 2027 generation further impacted by a combination of planned outages at Darlington and several parallel hydroelectric refurbishment and redevelopment outages. [redacted] ncluding from DNNP Unit 1 entering commercial operation and the first refurbished Pickering unit returning to service toward the end of the business plan period.



The IESO's Market Renewal Program (MRP) became operational on May 1, 2025. The OEB's 2024 decision on OPG's 2023 application addressed, among others, the then-anticipated impacts from MRP on OPG's regulated facilities until the effective date of OPG's new base regulated rates under the next application with the OEB. The plan reflects OPG's understanding and assumptions of the renewed market impacts, and OPG will continue to monitor these impacts to inform any future changes to the planning basis. In preparation for MRP's implementation, OPG completed the necessary upgrades to internal systems and processes to enable effective participation in the new market.

Nuclear Generation

The variability in the forecasted nuclear electricity generation over the business plan period reflects OPG's undertaking of major investments to expand and extend the operating life of its nuclear fleet, and the cyclical nature of nuclear planned outages.

In 2026, nuclear generation is expected to decrease by 4.9 TWh compared to 2025, primarily due to Pickering Units 5-8 being taken offline in September 2026 for the planned refurbishment and a major planned outage at Darlington Unit 3, partially offset by the expected return to service of Darlington Unit 4 from refurbishment. There are no major planned outages at Darlington in 2025.

In 2027, nuclear generation is expected to decrease by 13.8 TWh compared to 2026, primarily due to Pickering Units 5-8 anticipated to be in refurbishment and a combination of major planned outages at Darlington. The major outages at Darlington include a vacuum building outage requiring a full station shutdown, and a longer planned outage for Unit 2 to accommodate primary moisture separator replacements and the turbine control and auxiliary system upgrade work. OPG is leveraging lessons learned from the most recent Pickering VBO and industry best practices with an aim of reducing the outage scope and complexity of the Darlington VBO.

Planned nuclear generation increases by 8.0 TWh in 2028 compared to 2027, mainly reflecting a single major planned outage in the Darlington cyclical schedule, for Unit 1. The duration of the Unit 1 outage accommodates a non-routine primary side cleaning of the steam generators.

Planned nuclear generation decreases by 1.6 TWh in 2029 compared to 2028, primarily due to two major planned outages in the Darlington cyclical schedule, for Unit 3 and Unit 4. The duration of the Unit 3 outage accommodates the first of the four turbine rotor replacements at the station. As further discussed in *Nuclear Sustaining* under the *Capital Investments* section, this work will address a risk to continued safe and reliable operations, as well as increase the generating capacity of each unit by at least 21 MW.

Planned nuclear generation increases by 2.3 TWh in 2030 compared to 2029, mainly reflecting a single major planned outage in the Darlington cyclical schedule, for Unit 2, and the start of commercial operation of DNNP Unit 1 in October 2030. The duration of the Unit 2 outage accommodates the second turbine rotor replacement.

In 2031, nuclear generation is projected to increase by 3.6 TWh compared to 2030. This primarily reflects the anticipated return to service of refurbished Pickering Unit 5 in May 2031 and the first full year of commercial operation for DNNP Unit 1. Darlington has one major planned outage in its cyclical schedule in 2031, for Unit 1, which accommodates the third turbine rotor replacement.

All Darlington units are expected to transition to post-refurbishment normal operations by 2028. OPG is assuming an average forced loss rate (FLR) target of 2.0% at Darlington over 2028-2031 as it executes major emergent projects in support of post-refurbishment operations during the business plan period. OPG will further assess Darlington's steady-state FLR targets in subsequent planning periods upon completion of these equipment reliability investments. The Pickering FLR target remains at 3.5% until the start of the planned refurbishment, with an improved target anticipated once refurbished units reach steady-state operations. Based on industry experience and considering the first of a kind nature of the project, the generation plan for the first DNNP SMR reflects lower availability assumptions during the approximately 15 months of its initial operation covered by the plan.

Regulated Hydroelectric Generation

The planned regulated hydroelectric generation is largely stable over the business plan period. It is inclusive of outages to accommodate the ongoing refurbishment program and other life extension activities across the fleet, with unit availability averaging approximately 85% over the period. Generation is expected to be slightly lower in 2027 and 2028 due to a combination of refurbishment and redevelopment outages, and with the expectation that Niagara River returns to its long-term average waterflows in 2027. The plan reflects anticipated incremental capacity from the refurbishment and redevelopment projects.

Surplus baseload generation (SBG) conditions, as managed by the IESO, may continue to impact OPG's ability to schedule all of its available hydroelectric energy in the Ontario market and at times cause forgone generation in the form of hydroelectric spill. The methodology for calculating OPG's forgone hydroelectric generation due to SBG conditions has been updated to reflect the locational nature of Ontario's renewed market consistent with the OEB's 2024 decision regarding the MRP's anticipated impacts on OPG's regulated facilities. The impact of SBG conditions on OPG's generation is recorded in an existing regulatory variance account.

Contracted Generation

[redacted]

The plan reflects the successful selection of Lennox under the IESO's Medium-Term 2 procurement as announced in May 2025, securing a new five-year contract effective May 1, 2029, and the current contract term for Atikokan expiring in July 2029. Capital expenditure, operating cost and resourcing plans for these facilities are aligned accordingly. Both the IESO and OPG expect an increased need for generation capacity for Ontario's electricity grid post 2029, as system conditions tighten due to the recent shutdown of Pickering Units 1 and 4, the ongoing and anticipated nuclear refurbishments, and electricity demand growth. [redacted]

OPG's contracted hydroelectric facilities, developed and operated in partnership with Indigenous communities, will continue to provide over 3,300 MW of renewable generating capacity during the business plan period under 50-year energy supply agreements with the IESO.

Atura Power Generation

In addition to currently providing over 2,700 megawatts (MW) of capacity to Ontario's system, Atura's combined cycle fleet continues to leverage its flexibility to respond to changing conditions, providing a critical supply to address the province's increasing electricity demand and support energy transition and energy security goals.

Through this plan, Atura is seeking to increase the capacity of its fleet. This includes completing the Napanee BESS (250 MW) and the Napanee gas plant expansion (405 MW) that were previously awarded by the IESO under long-term capacity agreements, as well as seeking to secure new projects through the IESO's initial LT2 procurement window in the fourth quarter of 2025. Refer to *Subsidiaries – Atura Power* under the *Capital Investments* section for further details.

Operational Performance

OPG is committed to sustaining and investing in the reliability of its fleet to ensure a strong and resilient electricity system and support the province's energy transition. As part of its operational excellence imperative, OPG is focused on improving asset performance, increasing output and safely generating electricity from its existing operating fleet in a cost effective manner, and will continue to leverage and enhance organizational strengths to achieve the planned operational targets. At the same time, to help meet Ontario's growing energy needs, OPG must ensure that the Company's operating plans enable the successful execution of its major projects and position the new or refurbished assets for effective long-term operation. In managing its cost structures and resources to achieve these objectives, OPG will continue to maintain a focus on sustaining, and where possible, increasing efficiencies across the organization, and fostering a strong values-based culture.

Nuclear Operations

OPG is focused on maximizing the electricity generation potential of its nuclear fleet and driving continuous improvement in both operations and project performance. This includes preparing for and supporting the refurbishment of Pickering Units 5-8, with the goal of realizing sustained reliable and cost-effective performance over the station's extended life. It also includes completing the transition to post refurbishment operations and addressing emergent risks to high levels of performance at Darlington. Both stations are focused on improving equipment reliability and optimizing the planning and execution of outage and project work, including addressing equipment vulnerabilities, reducing station backlogs and improving outage efficiency as applicable, as well as enhancing leadership and talent development. As Canada's largest nuclear operator, OPG recognizes that, in addition to delivering on its business plan commitments, ensuring strong nuclear operations and project performance contributes to domestic energy and economic security objectives, and the Company's own growth potential.

OPG benchmarks a variety of measures to drive continuous improvement at its nuclear facilities, using indicators of performance on a per megawatt-hour (MWh) basis. To facilitate closer comparison, OPG normalizes the total generating cost per MWh (TGC) measure for CANDU technology factors when comparing against the primarily non-CANDU benchmarked utilities. In the near term, Darlington's TGC continues to be temporarily affected by higher project-related investments and reduced generation resulting from refurbishment outages up to 2026 and subsequently by reduced generation resulting from the VBO in 2027 and emergent work associated with the primary moisture separator replacements and the turbine rotor replacements. As this work is completed, Darlington's TGC is expected to achieve second quartile performance toward the end of the business plan period.

Pickering's TGC is forecasted to be in the third quartile prior to Units 5-8 being taken offline for the refurbishment, which includes the impact of restarting the sustaining project portfolio in support of post-refurbishment operations. Given the significant diseconomies of scale associated with a single online unit for a partial year, OPG has not normalized Pickering's projected TGC upon Unit 5 returning to service in 2031 and does not expect it to be a meaningful measure of performance during that period. As planned,

Pickering Units 1 and 4 ceased commercial operation and were permanently taken offline in the fourth quarter of 2024, after over 50 years of service. Refer to *Nuclear Sustaining in* the *Capital Investments* section for further details on the Pickering sustaining project portfolio.

While cost effectiveness is integral to OPG's operational excellence, maintaining industry-leading safety performance remains paramount. In 2024, OPG hosted a World Association of Nuclear Operators (WANO) mid-cycle site visit at Pickering. At Darlington, OPG most recently hosted a WANO continuum site visit in the second quarter of 2025. Through these visits, both stations were recognized as performing at the highest levels of operational safety and reliability. For Darlington, this was the thirteenth consecutive year of receiving such recognition. In the fourth quarter of 2025, Pickering station will host a WANO peer review, which includes an international safety assessment of the nuclear power plant conducted by an expert team to evaluate operations and recommend improvements. OPG is committed to striving for excellence and demonstrating continuous improvement across all aspects of nuclear operations, including adopting best practices and pursuing opportunities identified within the WANO reviews.

In the fourth quarter of 2024, the CNSC issued its most recent annual report, for the 2023 year, on the oversight and safety performance for nuclear power generating facilities. With respect to OPG's nuclear safety performance, CNSC staff determined that all 14 Safety and Control Areas for the Darlington and Pickering stations, and the Darlington, Pickering and Western waste management facilities met CNSC staff's expectations. In the second quarter of 2025, OPG published its annual estimated radiation dose exposure to members of the public from OPG's nuclear generating stations, which continue to remain a fraction of the legal limit. OPG will continue to operate its fleet with nuclear safety as an overriding priority.

In June 2024, the CNSC amended Darlington's operating licence to authorize the production of the cobalt-60 radioisotope, used in the health industry to sterilize surgical and medical supplies. The first harvest of cobalt-60 radioisotope at Darlington is expected by 2028. In September 2025, the CNSC announced the renewal of Darlington's operating licence for a 20-year period ending in 2045, the longest operating licence term ever granted to a Canadian nuclear generating station.

The Darlington and Pickering stations' key operational targets are further detailed in **Appendix 4**. OPG will develop appropriate performance measures and targets for the DNNP units as they approach commercial operation.

Ontario Renewable Generation Operations

OPG's hydroelectric fleet remains a mainstay of renewable, low-cost energy in the province. The Company's objective is to operate and maintain these facilities in a safe, reliable and cost-effective manner that optimizes their output based on water conditions and preserves their value for future generations. Key operational focus areas in the plan include continuing to embed a strong safety culture, enhancing equipment reliability through streamlined preventative maintenance, improving fleet wide consistency in asset planning, leveraging improved work management and maintenance tools, and expanding training programs. The Company aims to increase hydroelectric output, where feasible, by improving operational flexibility, optimizing outage planning and implementing plans to increase capacity and extend operating life.

While hydroelectric facilities enjoy operating lifespans that exceed those of other generating technologies, they require periodic renewal to ensure continued optimal performance. With the regulated fleet having an average age of approximately 90 years, OPG is currently in a period of increased investment needs to ensure that the assets can continue to help meet the province's energy needs for many more decades. The plan reflects such sustaining investments, most notably the ongoing turbine generator refurbishment program. OPG's ability to deliver on this program is facilitated by long-term partnerships secured with two hydroelectric original equipment manufacturers, which will provide the specialized resources and stability required to execute the projects, as well as the benefits of unit-over-unit project efficiencies expected within or across facilities with similar characteristics. Overall, the plan targets completing refurbishments that will sustain over 1,900 MW of generating capacity, or approximately 30% of the total regulated hydroelectric fleet.

OPG continues to evaluate opportunities to upgrade and expand the generating capacity of existing hydroelectric assets and, where aligned to their lifecycle, pursue their redevelopment. Through

investments in the plan, OPG plans to add approximately [redacted] of incremental capacity to the existing fleet, increasing the supply of clean energy in the province.

During 2022, the Office of the Auditor General of Ontario (OAGO) conducted a Value for Money audit of OPG's Management and Maintenance of Hydroelectric Generating Stations, recognizing OPG as a reliable provider of hydroelectric power to the province. The report highlighted opportunities for improvement, including the need to continue to explore opportunities to develop future hydroelectric supply. The audit also outlined recommendations to enhance OPG's maintenance planning and management systems, most of which have now been fully implemented or substantially progressed and are resourced in the plan. In December 2024, the OAGO released a Follow-Up Report building on its 2022 Value for Money Audit, and identified OPG as one of the three auditees, out of the total of 16 auditees, that made the most progress toward fully implementing the recommended actions.

OPG owns 66 hydroelectric generating stations and 239 associated dams on 24 river systems across Ontario and is committed to high standards of dam safety and waterways public safety. OPG is one of the first dam owners in Canada to have developed and implemented a dam safety program, and many aspects of this program have been assessed to be industry leading. During the business plan period, OPG will continue to make investments to sustain and strengthen dam safety across the fleet and will maintain a strong water safety education and outreach program.

OPG is planning to complete an external regulated hydroelectric cost benchmarking study in preparation for the upcoming 2027-2031 OEB rate application that will compare OPG's cost performance relative to peer utilities. OPG also internally benchmarks reliability performance and expects performance on availability metrics to remain strong relative to peer utilities.

The key operational targets for Ontario-based hydroelectric operations are further detailed in **Appendix 4.**

Atura Power

In line with its commercial strategy, Atura continues to focus on improving its combined cycle plant start reliability and availability, particularly during peak demand periods. Atura's outage program will continue to align with published energy market forecasts and leverage an agile asset management program to prioritize managing equipment risks and optimize timing.[2]

[redacted]

The key operational targets for Atura are further detailed in **Appendix 4**.

[2] Consistent with the OEB's generation licence requirements, Atura's energy management and outage plan for its fleet is developed separately from the rest of OPG's operations, ensuring that no competitively sensitive information is disclosed between the organizations.

Eagle Creek Renewable Energy

In October 2025, OPG entered into an agreement to sell its wholly-owned subsidiary in the United States, Eagle Creek, with the transaction expected to close in the first quarter 2026, subject to customary closing conditions. The plan reflects anticipated net proceeds from the transaction of approximately [redacted], which will support funding needs for the Company's capital investment program. The plan assumes no further earnings, production or capital expenditures associated with Eagle Creek after the end of 2025.

Laurentis Energy Partners

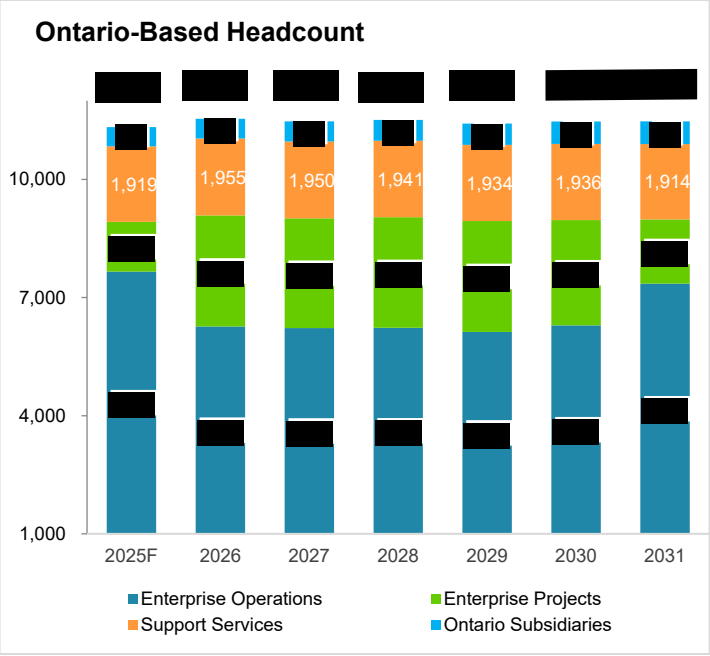
LEP continues to pursue a strategy of expanding the production of isotopes for medical and other uses through construction of a second TDS to be installed at Darlington Unit 3 and by securing commercial offtake agreements. The production of the Molybdenum-99 isotope will commence through the existing TDS at Darlington Unit 2 following final regulatory approvals. Molybdenum-99 is used in diagnostic imaging and cancer detection, with Darlington being the first commercial-scale reactor to produce this isotope in North America. LEP has also entered into commercial agreements to produce Yttrium-90 and Lutetium-177, which are used in the treatment of certain cancers. The second TDS will have the capacity to irradiate targets for producing isotopes like Molybdenum-99, Yttrium-90 and Lutetium-177, helping to meet the growing demand. The unique design of CANDU reactors allows medical isotopes to be produced and harvested while the reactor is online, providing the ability to secure a domestic supply of these life-saving products.

LEP will also continue to maintain a service line of business across traditional and nascent markets within the nuclear sector and beyond. In 2024, a subsidiary of LEP entered into a long-term framework agreement pursuant to which it will provide project management services for the Unit 1 refurbishment at the Cernavoda Nuclear Power Plant in Romania.

[redacted]

Ontario-Based Headcount

OPG is focused on maintaining strong performance from the existing assets and renewing its fleet, while investing in new generation growth pathways. In view of the heightened focus on infrastructure generally and energy infrastructure specifically, as well as an increasingly competitive labour market for such resources, OPG's priority is to meet the need for key skillsets and roles using talent retention, development and attraction tools that will successfully enable the Company's projects and operations, now and in the future. The plan includes workforce strategies in support of these objectives while balancing the need for sufficient resourcing flexibility during this period of change for the organization. Given these objectives and the resourcing requirements for planned projects including the Pickering Refurbishment, OPG no longer anticipates any significant workforce downsizing, eliminating the need for the associated restructuring costs.



OPG had previously anticipated eliminating approximately 3,000 positions as a result of the Pickering shutdown. In parallel with planning for the Pickering Refurbishment, the Company has been realigning its resourcing strategy to be able to redeploy the affected workforce to enterprise projects, where possible. In addition to mitigating project resourcing risks, this strategy will allow OPG to retain key skillsets and expertise in order to manage talent availability, attraction and training risks to future operations, once Pickering Units 5-8 return to service. These outcomes are being supported by OPG's focus on labour deployment flexibility in its negotiated labour agreements. At the peak, over 40% of OPG's regular workforce is expected to directly support the delivery of refurbishment, development, or sustaining projects during the business plan period.

Headcount Trends

The plan reflects a headcount profile based on the resourcing strategy discussed above and aligns to the operations and project demands over the period, including the workforce associated with the DNNP SMRs. Under the terms of the DNNP partnership, OPG will retain the SMR workforce as the project manager and operator of the facility.

Enterprise Operations headcount is forecasted to [redacted] by approximately [redacted] in 2026 upon Pickering Units 5-8 entering the planned refurbishment and remains relatively stable until [redacted] by approximately [redacted] in 2031 as Pickering Unit 5 returns to service. The increase of approximately 160 in Enterprise Operations headcount in 2030 reflects the start of commercial operation of DNNP Unit 1. During the Pickering Refurbishment period, Enterprise Operations will include the workforce required to maintain Pickering Units 5-8 and associated infrastructure, systems and processes, in order to meet regulatory requirements, preserve the assets and ensure readiness for the return to service. [redacted]

As the planned Pickering Refurbishment enters the execution phase subject to the Province's approval, Enterprise Projects headcount is forecasted to [redacted] by approximately [redacted] compared to 2025, including the employees transitioning from Pickering station operations. It is then anticipated to [redacted] by approximately [redacted], as employees transition back to Enterprise Operations upon return to service of Pickering Unit 5. The DNNP is expected to utilize fewer internal staff than the Pickering Refurbishment as it is a new construction project with a different type of work, resource skillsets and trades jurisdiction, and employs an integrated project delivery model such that staffing requirements are filled in greater part by the contract partners.

Support Services underpin all of the Company's operations, projects and growth initiatives, and include such centre-led corporate functions as Corporate Technology Services, Human Resources, Finance and Real Estate (all as part of Corporate Services) and Supply Chain (as part of Commercial Operations). These functions are integral to sustaining core organizational processes, maintaining the corporate infrastructure, providing risk management, supporting workforce activities, ensuring governance, oversight and compliance, and advancing business development. Support Services headcount is planned to remain relatively stable throughout the business plan period, including as Pickering Units 5-8 transition through refurbishment. Given OPG's overall economies of scale and the SMR operating model, the commercial operation of DNNP Unit 1 is not expected to have a material impact on Support Services' headcount.

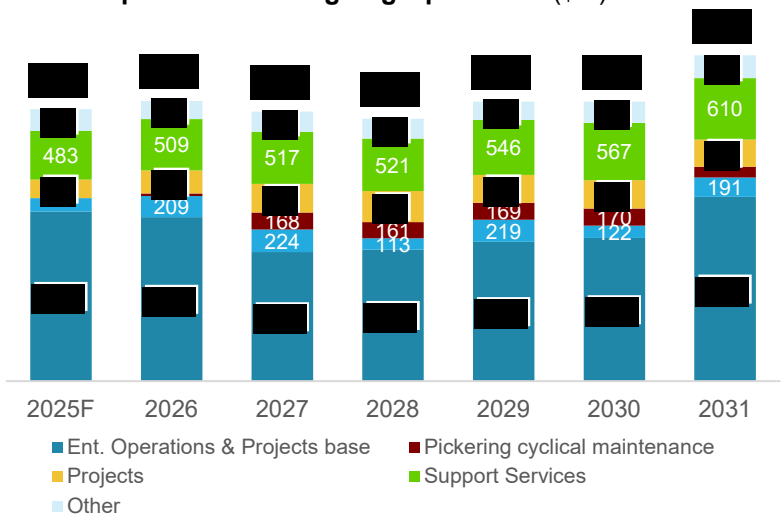
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Operations, Maintenance & Administration Costs

Operating costs in the plan reflect the evolution of the Company from an organization that was planning for a significant downsizing to one entering a period of growth and renewal. The operating costs trajectory over the period reflects resourcing requirements and strategies in support of OPG's role in meeting the Province's IEP and energy security objectives, commitment to innovation, and maintaining the long-term value of its assets, while continuing to pursue efficiencies and manage key enterprise risks.

OM&A Expenses from Ongoing Operations ($M)



Refer to Appendix 3 for full breakdown of OM&A from Ongoing Operations.

Base Operating Costs

For most of the business plan period, Enterprise Operations Base OM&A costs are expected to [redacted] as Pickering station resources are realigned to support the planned Units 5-8 refurbishment and the ongoing cyclical maintenance activities for these units during the refurbishment window. At the same time, Enterprise Operations Base OM&A costs will continue to fund the necessary operational and oversight processes that remain applicable to the station during a refurbishment outage, including in such areas as security and emergency preparedness, engineering and site monitoring, environmental activities, fleet management, nuclear oversight and regulatory compliance, and industry initiatives. Station inspection and maintenance activities during the refurbishment outage will be funded through Pickering cyclical maintenance costs, discussed below.

In 2031, forecasted Enterprise Operations Base OM&A costs begin to [redacted] with the return to service of Pickering Unit 5, and also include approximately $100 million in incremental costs for the first full year of commercial operation for DNNP Unit 1. The forecasted operating costs for DNNP Unit 1 reflect OPG's operating strategy design and associated staffing model assumptions for the SMRs.

The OM&A costs associated with each of the first refurbished Pickering unit and the first DNNP unit coming online are impacted by substantial relative diseconomies of scale associated with operating one out of four possible reactors at a nuclear station. In both instances, the OM&A costs reflect the respective fixed costs required to operate at least one of such reactors. The incremental OM&A costs for the operation of subsequent units coming online beyond the business plan period will be significantly lower.

Support Services Base OM&A costs are projected to increase over the business plan period, mainly due to higher expenses associated with the Company's information technology infrastructure. As discussed further under *Digital Technology*, OPG is focused on addressing obsolescence risks and supporting upgrades for key enterprise systems, as well as investing in technology enhancements to support cybersafe, reliable and efficient operations. These initiatives, together with observed inflationary trends and increased demand for digital tools across the organization, are expected to result in higher software and maintenance costs over time. By 2031, Support Services Base OM&A costs are also higher to reflect anticipated incremental information technology and facilities maintenance requirements in support of the commercial operation of DNNP Unit 1, as well as the return to service of Pickering Unit 5.

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As it undertakes planned major projects and implements associated resourcing strategies, the Company will remain focused on cost performance and continue to pursue operational efficiencies within the resulting cost structures, at the enterprise and functional levels. Some of these initiatives currently include:

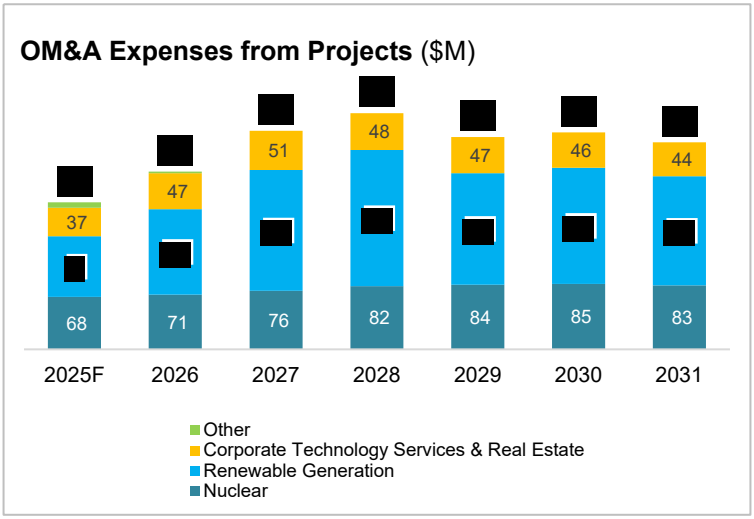
- ***Digital Technology:*** Improving data capability to enhance decision making, increasing workforce connectivity and digital proficiency, modernizing managed systems and work processes, strengthening core infrastructure, and supporting growth through scalability;
- ***Project Management***: Enhancing project management capability through automation and optimization, including integration of digital tools, centralization of data architecture, knowledge management through artificial intelligence, and enhancing reporting capability;
- ***Workforce Strategies***: Securing an engaged, capable and adaptable workforce to enable business objectives, while managing risks and ensuring sufficient resourcing flexibility through redeployment strategies, upskilling/reskilling, succession planning and change management;
- ***Nuclear Planned Outages***: Improving planned outages on refurbished units by optimizing and reducing scope, streamlining workflows, and leveraging innovation, technology, industry experience and resourcing to optimize outage planning and schedules, where possible; and
- ***Supply Chain***: Continuing to build on existing supplier relationship management, onboarding and capability, materials management, and warehouse efficiencies.

Nuclear Outage and Enterprise Non-Capital Project Costs

The variability in forecasted nuclear outage costs over the business plan period is driven by planned outage cycles and scope, with costs averaging $173 million annually, excluding Pickering cyclical maintenance work. The costs are higher in 2027 due to the Darlington VBO, in 2029 due to two major planned outages in the Darlington cyclical schedule, and in 2031 due to the first refuelling outage on DNNP Unit 1. See *Ontario Electricity Generation* for further information.

Pickering cyclical maintenance costs are non-refurbishment costs for cyclical inspection and maintenance activities in support of Units 5-8 at the Pickering station planned during the refurbishment window. They are aligned to OPG's aging and life cycle management programs and will ensure compliance with regulatory requirements, preserve optimal operability and ensure readiness to return the units to service. This includes activities typically associated with a major planned outage or online work during normal operations. These planned costs average approximately $166 million over the 2027-2029 period, declining to $107 million in 2031 as Unit 5 returns to service, and include funding for station resources expected to execute this scope.

Nuclear project OM&A costs are expected to increase from $68 million for 2025 to approximately $83 million by the end of the business plan period, mainly in line with restarting a capital project portfolio allocation to Pickering to support post refurbishment operations. The funding will be managed based on identified operational needs and the scope of associated capital projects that is not eligible for capitalization.



Renewable Generation project OM&A costs relate to non-capital work associated with the hydroelectric refurbishment and redevelopment programs and other non-routine work not eligible for capitalization. The trajectory of the forecasted costs, which average [redacted] per year, [redacted] The [redacted] in expenses during 2027 and 2028 reflects the overlapping timing of unit refurbishments at the Sir Adam Beck complex and the ongoing redevelopments of several smaller facilities.

Forecasted OM&A costs from projects executed through Corporate Technology Services and Real Estate functions (within Corporate Services) increase over the period, reflecting additional funding allocated to support the digital technology strategy including planned replacement of major enterprise systems to address obsolescence risks.

Pickering Refurbishment Non-Capital Costs

The plan includes a total of $383 million in OM&A costs over the business plan period related to major component removal and waste management as part of the Pickering Refurbishment scope that are not eligible for capitalization. These costs vary by year based on underlying activities. The estimates for these costs align to the Pickering Refurbishment Release Quality Estimate (RQE), discussed further under *Capital Investments.*

Darlington New Nuclear Project Operational Readiness

The success of the DNNP will in part depend on ensuring readiness to safely, reliably and effectively operate these first-of-a-kind units once they are online. Such planning and preparation efforts have begun and will ramp up toward 2030, with associated OM&A costs of $237 million included in the plan. These funds will be in large part used to implement comprehensive employee training programs tailored to the operation and maintenance requirements of the SMRs, creating a specialized workforce with technology-specific expertise. The funds will also cover planning activities such as developing operational processes and procedures, establishing work management functions for scheduling routine and outage maintenance, planning for emergency management and fire protection, implementing plant maintenance protocols, defining oversight systems, and establishing operational targets.

Pension and OPEB Costs

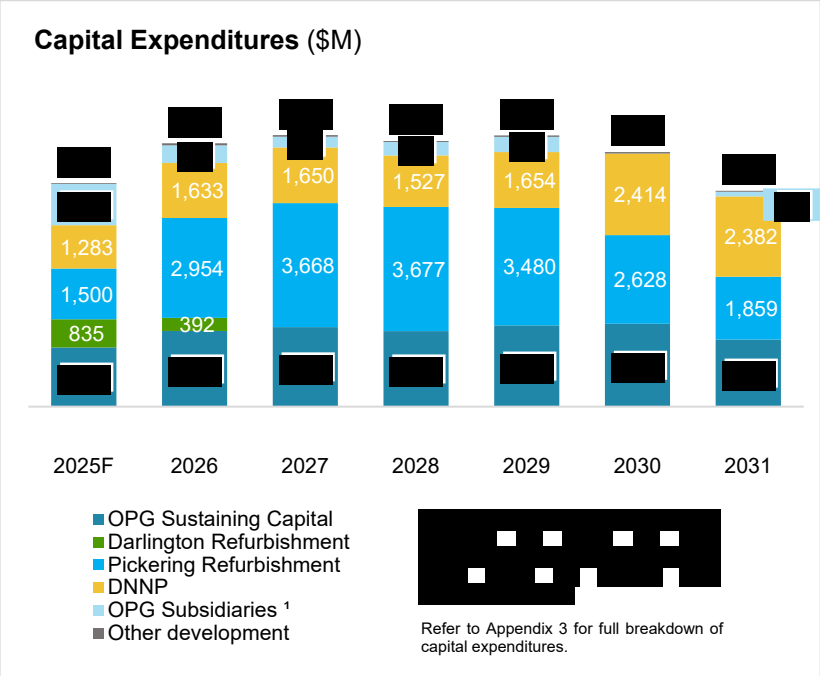
Pension and OPEB costs before the impact of regulatory deferral and variance accounts are forecasted to increase from the 2025 levels, mainly reflecting projected increases in pensionable earnings, interest costs on benefit obligations and updated actuarial assumptions, partially offset by projected pension asset returns. The forecasted pension and OPEB costs are based on the headcount levels in the plan.

Prior to the resetting of regulated rates in 2027, the net income impact of the regulated business' portion of pension and OPEB cost changes is expected to be largely offset by existing regulatory deferral and variance accounts, which capture the differences between forecasted amounts reflected in regulated rates and OPG's actual pension and OPEB costs. For 2027 onwards, new regulated rates are expected to be set based on the accrual accounting method, consistent with previous OEB conclusions and approvals.

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Capital Investments

OPG is embarking on a transformational capital investment program during this business plan period. These significant expenditures ranging from refurbishments of some of Ontario's longest standing power supply assets to delivering new generation projects will help meet Ontario and Canada's domestic energy goals, prepare the electricity system for the future and support economic growth. In undertaking these projects, OPG will continue to proactively and meaningfully engage with Indigenous communities and remains committed to creating social and economic benefits through partnership and collaboration with the First Nations.



Over the seven-year period, OPG's planned capital expenditures are approximately [redacted]. For the regulated business, these investments are estimated to increase the total capital in-service rate base (net of depreciation) to approximately $32 billion for the nuclear operations and $12 billion for the regulated hydroelectric operations by 2031. These figures do not reflect further capital expenditures that may arise for any new large nuclear or greenfield hydroelectric projects that are ultimately approved to proceed.

OPG and its subsidiaries continuously strive to be an industry leader in project management capability and performance. As the Company enters a level of construction activity it has not seen in recent decades, OPG will leverage its success with the Darlington Refurbishment and other recent projects to deliver on the business plan commitments.

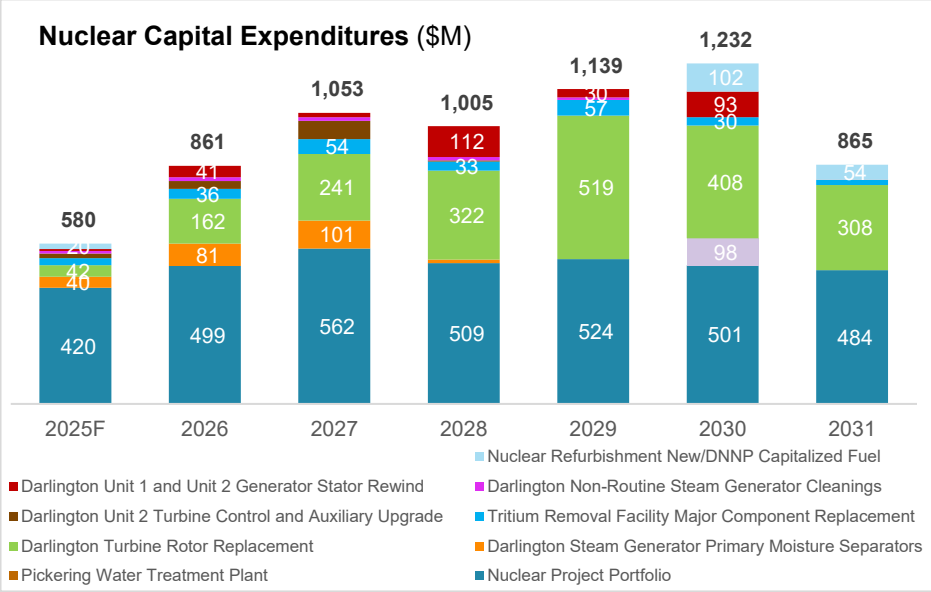
Under the CCR mechanism assumed in the plan, future interest during construction for the DNNP and the Pickering Refurbishment would be recovered through nuclear regulated rates as incurred and therefore would not be capitalized on the balance sheet or included in the in-service rate base. Capital expenditures and in-service amounts for these projects are shown in the plan on such basis, unless otherwise noted.

Sustaining Capital

Maintaining the availability and reliability of OPG's existing fleet is a critical component of meeting current and future energy needs. OPG's sustaining investments are based on asset management principles aimed at ensuring that capital is deployed in a manner that derives the greatest value while mitigating operational risks. Over the business plan period, excluding subsidiaries, OPG plans to invest approximately [redacted]ion in sustaining expenditures, including approximately $6.7 billion for the nuclear fleet, $6.5 billion for the regulated hydroelectric assets, $1.1 billion in digital technology projects, and approximately [redacted] for other assets. OPG will continue to monitor and where possible mitigate the effects of macroeconomic risks to these budgets, such as through procurement and contracting strategies.

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Nuclear Sustaining



The nuclear sustaining projects of $6.7 billion over the business plan period include $3.5 billion for the Darlington and Pickering project portfolios, certain major emergent or otherwise necessary investments to address risks to achieving Darlington's post-refurbishment operations, and certain other non-portfolio projects. Major non-portfolio projects include $2.0 billion for the first three Darlington turbine rotor replacements, $235 million to complete the Darlington steam generator primary moisture separator replacements, $253 million to progress the Tritium Removal Facility Major Component Replacement, $115 million for the Darlington Unit 2 turbine control and auxiliary system upgrade, and $300 million for the Darlington Units 1 and 2 generator stator rewind. Funding for capitalized costs for refurbished and new units is also included.

The planned nuclear project portfolio averages $500 million annually and has a relatively stable trend over the business plan period, as the Darlington program decreases toward the anticipated long-term steady state levels and the restarted Pickering program ramps up in contemplation of post-refurbishment operations of Units 5-8. The prioritization of the portfolio will reflect operational and risk management needs and regulatory requirements, taking into account resourcing and financial capacity.

The Darlington capital program will continue to focus on ensuring that the refurbished station is well positioned for sustained strong reliability performance over the long term. The Pickering capital program represents a change from recent years, when very limited sustaining work was conducted at the station due to the assumed upcoming end of commercial operation. Over the business plan period, the larger Pickering program is planned to focus on sustaining work that is more efficiently executed during the multi-unit refurbishment window, supports improved post refurbishment unit reliability, and renews necessary station infrastructure. These projects are planned to be managed separately from the Pickering Refurbishment, which will be focused primarily on the rehabilitation or replacement of critical life-limiting components and the completion of upgrades to meet regulatory requirements. This approach is consistent with the Darlington Refurbishment – it positions the units for strong performance while balancing the need for more extended planned outages in the future with managing the complexity of the refurbishment scope. OPG will continue to develop and prioritize the Pickering sustaining portfolio to ensure it optimally supports post-refurbishment operations and successful execution of the Pickering Refurbishment, subject to the Province's approval.

The Darlington turbine rotor replacements for the four units are required to sustain safe and efficient turbine operation and prevent the risk of failure over the remaining station life. They will consist of the installation of upgraded high efficiency equipment including new casings with stationary blades. This work also provides an opportunity to increase each of the units' generating capacity by at least 21 MW through the use of upgraded technology and to support future outage efficiencies. Given the global demand for turbine generator major components, OPG has been focused on securing access to manufacturing slots to ensure timely delivery of this equipment to mitigate the risk of failure.

The goal of the Tritium Removal Facility Major Component Replacement program is to improve the reliability of the tritium removal facility (TRF), ensuring a consistent supply of de-tritiated heavy water critical to the continued operation of Ontario's CANDU fleet. The TRF is currently the only facility of its kind in Canada and has been in operation for over 30 years. The program is expected to be executed in

a phased manner over a number of years, beginning with several planned TRF outages during the business plan period.

As previously identified, the Darlington Unit 2 turbine control and auxiliary system upgrade was deferred from the Darlington Refurbishment scope in order to mitigate execution risk for Unit 2, being the first unit to be refurbished. This work is required to mitigate the aging risks of the components and associated production loss, and to ensure reliable operations over the post refurbishment period. Equivalent work has now been successfully executed on the other three units as part of the Darlington Refurbishment.

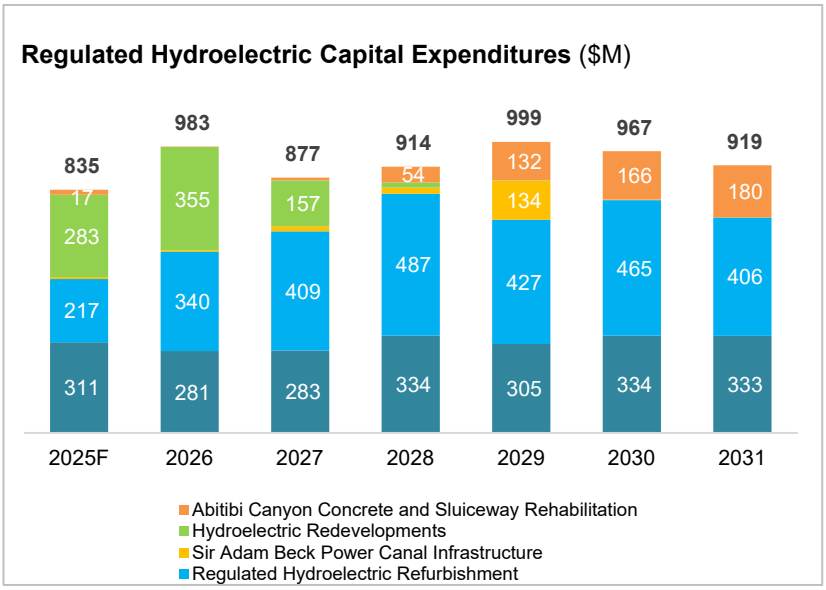
The plan also includes major emergent work identified through inspections showing evidence of degradation on the Darlington Units 1 and 2 generator stators. To address this risk, OPG has determined that the generator stators will need to be rewound.

Digital control computers (DCC) replacement is considered within the Pickering Refurbishment scope for subsequent units. However, given the overall high level of complexity associated with executing the first unit's refurbishment, OPG plans to complete the Unit 5 DCC replacement as a separate project in order to help mitigate risks to the unit's critical path. This strategy is modelled on a similar, successful strategy that deferred the turbine control and auxiliary system upgrade from the Darlington Unit 2 refurbishment for risk mitigation reasons. The business plan period reflects the planning and definition activities for the Unit 5 DCC replacement work.

Additionally, in 2030, OPG currently plans to replace the Pickering Water Treatment Plant to support post-refurbishment station operations, under a finance lease arrangement with a third party specializing in high purity demineralized water management.

Regulated Hydroelectric Sustaining

The hydroelectric sustaining capital funding across 54 regulated facilities totals approximately $6.5 billion over the business plan period, comprising $2.2 billion for the fleet-wide project portfolio, $2.8 billion for the ongoing turbine-generator refurbishment program, $0.8 billion for redeveloping certain smaller facilities, $0.6 billion for major rehabilitation work at the Abitibi Canyon station and $0.2 billion for major infrastructure work on the Sir Adam Beck power canal.



The annual fleet-wide project portfolio represents an increase from historical levels, averaging approximately $312 million over the business plan period. The increase reflects investments required to address asset condition and ensure continued safe and reliable operations. A key focus area is on concrete structure, dam and sluiceway rehabilitation works to address degradation related to age and environmental factors and support dam safety. Some of the major works include the rehabilitation of Hayes Lake Dam supporting the Aguasabon generating station and the refurbishment of the Otto Holden stop log sluice piers. The portfolio also covers funding for water control, civil rehabilitation and other projects, as well as increased levels of investment in station service and transformer upgrade projects to complement the turbine-generator refurbishment program. Portfolio funding will be prioritized based on operational and risk management needs, taking into account hydrological conditions, geographical constraints, and resourcing and financial capacity.

OPG is also continuing a major program of turbine-generator refurbishments in order to maintain the fleet's reliability and maximize its ability to support increasing electricity demand. The forecasted refurbishment expenditures increase from $217 million in 2025 to $406 million in 2031, mainly as units at

the Sir Adam Beck II station enter execution in 2027. Overall, OPG is planning to invest in refurbishments of approximately 90 units at 26 of its regulated hydroelectric facilities over the business plan period, scheduled based on asset condition, hydrological conditions and resource capacity in each of the operating regions. This includes 20 units at Sir Adam Beck and R.H. Saunders stations. Of these units, 65 are planned to be placed in-service during the period, sustaining over 1,900 MW of generating capacity or approximately 30% of the regulated hydroelectric fleet. Throughout 2024 and into 2025, the Province announced its support of OPG's planned refurbishments, including at the Sir Adam Beck and R.H. Saunders stations. In addition to ensuring continued reliable operations, these projects provide an opportunity to increase, where feasible, generating efficiency and capacity through technological improvements.

OPG continues to evaluate the condition and redevelopment potential of the regulated hydroelectric fleet as some of the oldest, smaller facilities approach end of life. Despite their advanced age, these assets play an important role in generating energy during a period of growing demand, while supporting local needs. The plan reflects the redevelopment of five such facilities currently in the execution phase, including the Kakabeka Falls station, based on the applicable cost and schedule commitments as approved by the Board. Redevelopment projects have greater scope than refurbishments by also replacing or rehabilitating civil infrastructure and other structures, such as intakes, tunnels, or penstocks. Once completed, the current redevelopments are expected to secure over 50 MW of renewable capacity for an additional 80 to 90 years, including incremental generation expected to be achieved through the use of improved technology and optimization of water flows. Should additional redevelopment sites be identified to proceed beyond the initiation phase, capital funding will be considered in future plans.

The plan includes funding for major rehabilitation of the concrete structures and sluiceway at the Abitibi Canyon station in Northeastern Ontario. These investments over the business plan period are necessary to address concrete deterioration and improve sluiceway and superstructure equipment reliability at this 345 MW, 92-year-old generating facility. The estimated expenditures consider the anticipated size and complexity of the rehabilitation work, including dam repairs and upstream concrete liner rehabilitation, the scope for which is being developed.

Mainly in the 2027-2029 period, the plan also includes funding for the first two phases of major infrastructure work on the 100-year old canal that supplies water from the Welland and Niagara Rivers to the Sir Adam Beck generating complex, passing through the City of Niagara Falls. This work is currently in the early planning phase. The investment, which will install the capability to isolate and drain the canal, will facilitate future refurbishment work on the canal liner and associated structures to conduct necessary repairs and address degraded canal flow capability.

Digital Technology

Technology continues to play a critical role in enabling OPG's strategic objectives, optimizing operations and supporting project delivery, and is shaped both by evolving internal needs and the external landscape. The plan includes capital funding to advance the Company's digital strategy aimed at both managing near-term risks and ensuring future readiness. Over the period, planned funding comprises $968 million, or approximately $138 million per year, for an enterprise digital technology portfolio, and a total of $167 million to enable DNNP's operational requirements. These budgets are managed by OPG's Corporate Technology Services organization (within Corporate Services).

A key component of the Company's digital strategy is to update critical enterprise resource planning and management systems that are reaching obsolescence or have an uncertain vendor support roadmap. In addition to ensuring continued effective operations, this will provide an opportunity to better optimize and integrate the systems and modernize processes. These projects, covering OPG's existing financial, supply chain and asset management systems, have been considered in the enterprise digital technology portfolio funding and are currently in various stages of initiation and planning. They are expected to be completed or substantially progressed during the business plan period. The remainder of the portfolio will be used to strengthen core capabilities and fund emerging needs in areas including technology optimization and innovation, cybersecurity, operations and engineering technology improvement, and data management and decision-making. With respect to DNNP, the planned funding will implement new digital tools and applications that will help enable the operating strategy for the SMRs, including smart devices, digital worker technologies and a new, streamlined asset management system.

Darlington Refurbishment

In November 2024, OPG successfully reconnected to the grid the refurbished Darlington Unit 1, ahead of the original schedule. This followed the early return to service of Unit 3 in 2023. The final unit, Unit 4, is expected to be safely returned to service in the first half of 2026, ahead of the original schedule. Forecasted capital expenditures to complete the project are $835 million in 2025 and $392 million in 2026. Upon returning Unit 4 to service in 2026, capital expenditures totaling approximately $2.3 billion are forecasted to be placed in service. The total project cost, including the impacts of the COVID-19 pandemic and inflation, is forecasted under the approved $12.8 billion budget previously approved by the OEB. The revenue requirement impact of differences in the timing or amount of the in-service capital compared to OEB approved forecasts is recorded for future disposition in a regulatory variance account authorized pursuant to O. Reg. 53/05.

Pickering Refurbishment

In January 2025, the Province announced its approval of OPG's plan to proceed with the project definition phase as the next step toward refurbishing Pickering Units 5-8. This work is tracking within the cumulative Board-approved budget to date of $6.2 billion.[3] During this definition phase, OPG has been completing a high-confidence cost estimate and schedule, progressing detailed engineering, furthering procurement and contracting work, optimizing scope, developing the project execution plan and progressing prerequisite facilities and infrastructure work. The remaining definition phase is expected to last through 2026. The majority of the budgets released to date relate to commitments required to secure long-lead materials, rather than immediate cash outflows. The total generating capacity of Pickering Units 5-8 is over 2,000 MW.

In June 2025, OPG submitted an application to the CNSC for renewal of Pickering's operating licence, which includes the planned refurbishment activities. The two-part public hearing on the application is scheduled to be held in April 2026 and June 2026.

Based on detailed engineering and work planning, OPG has now prepared the RQE for the four-unit refurbishment to be approved by the Board. The plan reflects this high-confidence cost estimate and schedule, with the project prepared to progress into the execution phase beginning in 2027, subject to approval by the Province. Based on the high-confidence schedule, the refurbishment of the four units is expected to be completed by 2034, with the first unit, Unit 5, returning to service in May 2031. Unlike Darlington Refurbishment, the Pickering Refurbishment will execute overlapping work on all four units. The high-confidence cost estimate for the four-unit refurbishment is $26.8 billion.[3] The business plan period reflects approximately $19.8 billion in capital expenditures to complete the definition phase and progress execution. The forecasted capital in-service amount for Unit 5 and pre-requisite projects is $9.8 billion during the business plan period.

In the upcoming rate application for 2027-2031, OPG will request the OEB's approval for the forecasted in-service amounts and associated revenue requirement impacts of the Pickering Refurbishment during this period based on the approved RQE. The revenue requirement impact of any differences in the timing or amount of the in-service capital compared to OEB approved forecasts will be recorded for future disposition in a regulatory variance account authorized pursuant to O. Reg. 53/05.

Darlington New Nuclear Project

The Board has approved the RQE, together with the associated funding release, for the execution of Unit 1 and common site scope of the DNNP. This high-confidence cost estimate and schedule reflect three years of detailed planning and preparation undertaken since the original technology selection decision was made at the end of 2021. In April 2025, the CNSC announced its decision to issue a power reactor construction licence to OPG for the first DNNP SMR, valid until March 31, 2035. In May 2025, the Province announced its support for OPG to proceed with the execution phase of the first DNNP SMR. The plan is aligned to the approved RQE for the first unit and common site scope, committing the Company to deliver G7's first grid-scale SMR by October 2030. The budget for this work is $7.7 billion[3], including site scope common to all four planned DNNP units. The associated forecasted capital in-service amount is $6.6 billion during the business plan period. OPG expects to file an operating licence application for the first SMR with the CNSC in 2026.

[3] Including interest on the expenditures.

As also approved by the Board, OPG is continuing to advance the definition phase for the three additional DNNP small modular reactors. Construction of these subsequent units would commence following the first unit's construction and will incorporate the resulting lessons learned, subject to completing the respective RQE(s) that will contain the final cost and schedule commitments for these units and the receipt of requisite approvals. For financial and resource planning purposes, the plan includes estimated expenditures for subsequent units' execution through 2031, bringing the total forecasted project capital expenditures over the period to approximately $12.5 billion. The total generating capacity of the four-unit DNNP is expected to be approximately 1,200 MW, with the three additional SMRs expected to enter service by 2035.

In the upcoming rate application for 2027-2031, OPG will request, through the expected DNNP partnership, the OEB's approval for the forecasted in-service amounts and associated revenue requirement impacts for DNNP Unit 1 and common site scope, based on the approved RQE. The revenue requirement impact of any differences in the timing or amount of the in-service capital compared to OEB approved forecasts is expected to be recorded for future disposition in a regulatory variance account. Such an account is currently authorized for OPG pursuant to O. Reg. 53/05 and is assumed to be similarly authorized for the DNNP partnership as part of its rate-setting framework.

Chats Falls Hydroelectric Expansion

OPG is pursuing an opportunity to add a new 33 MW generating unit in an empty bay at the existing Chats Falls generating station. This work is currently in the early planning phase. Subject to completing the necessary planning, the plan assumes the project would enter execution in 2028 and be completed beyond the business plan period. The plan allocates approximately $99 million of OPG's capital funding to the project. The Chats Falls station is jointly owned by OPG and Hydro-Québec and its costs and output are shared between the two organizations. OPG's share of the output receives the hydroelectric regulated rate.

Exploring New Nuclear Generation

In line with the Province's vision for meeting Ontario's electricity demand, OPG is advancing early site assessment and engagement work for potential locations for new nuclear generation, as approved by the Board. This includes delivering on the Province's request for OPG to engage with Indigenous and municipal leaders to explore support for new energy generation, including nuclear, at three OPG-owned sites: Wesleyville, Nanticoke and Lambton. All three sites are already zoned for electricity generation and are proximate to transmission. As one the province's largest landowners, OPG will continue to identify and evaluate opportunities to optimize its sites to enable existing and potential new generation options.

In January 2025, with the willingness of the Michi Saagiig of the Williams Treaties First Nations and a formal expression of interest from the Town of Port Hope, the Province asked OPG to specifically explore new nuclear generation opportunities at the Wesleyville site. Based on OPG's early assessment, the Wesleyville site could host up to 10,000 MW of new nuclear energy generation, which could power the equivalent of approximately ten million homes. OPG is collaborating with local communities and First Nations to determine their support for a potential new large nuclear generation project as part of the exploration process.

The plan includes non-capital expenditures of $198 million over 2025 and 2026 to advance planning and preparation activities for potential new nuclear generation on OPG's sites. This includes such activities as: technology and site screening, Indigenous engagement and consultation and community engagement for the potential sites, documentation, data collection and analysis required in support of an Impact Assessment and a potential Licence to Prepare Site for Wesleyville, and early design phase planning activities to support technology evaluation. To the extent not reflected in the nuclear regulated rates, these costs are eligible for recovery through an existing regulatory variance account authorized under O. Reg. 53/05, subject to the OEB's review. OPG currently expects to request the Board's approval of technology selection and a decision whether to proceed with the Licence to Prepare Site application for Wesleyville, along with the associated initiation phase activities, by the end of 2026. The plan does not include capital expenditures for potential new nuclear generation development, which would be subject to future approvals.

[redacted]

Exploring New Hydroelectric Generation

OPG is undertaking early project initiation efforts for potential new hydroelectric development in the province to ensure readiness to advance approved project paths with appropriate revenue mechanisms. In April 2025, the Province announced plans to collaborate with the Taykwa Tagamou Nation and the Moose Cree First Nation on new hydroelectric generation opportunities in the Moose River Basin in Northeast Ontario. The partnership involves co-planning with OPG, as the partner-in-principle, to explore potential new hydroelectric stations, the proposed Nine Mile Rapids and Grand Rapids generating stations, which could collectively produce up to 430 MW of clean electricity. OPG is also evaluating the potential for pumped storage at the existing Lower Notch hydroelectric site. The plan allocates approximately [redacted] of non-capital expenditures to the above activities and does not include any potential subsequent capital expenditures, which would be subject to future approvals.

Subsidiaries

Atura Power

[redacted]

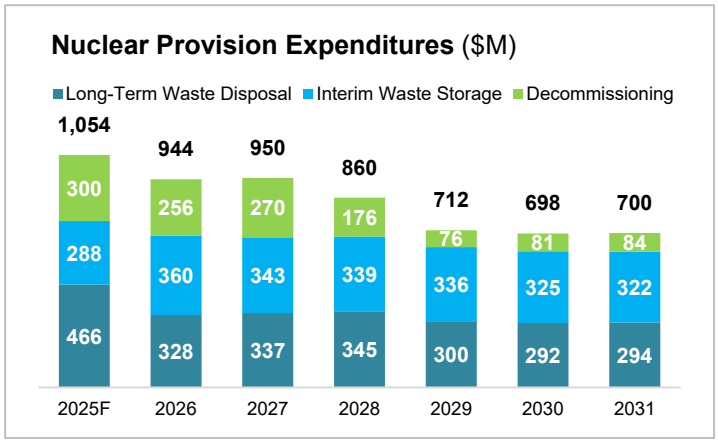
As part of Atura's development activities, [redacted] to complete the 250 MW four-hour Napanee BESS and [redacted] to complete the expansion of the Napanee natural gas plant. The Napanee BESS will enhance Ontario's ability to meet peak demand by storing electricity off-peak when power demand is low and returning it to the system at times of higher demand. The Napanee gas plant expansion project will add an additional combustion turbine generator unit at the site, making up to 405 MW of electricity output available to the grid. The Napanee BESS is expected to be completed in 2026 and the Napanee gas plant expansion in 2028, operating under a 21-year and 12-year IESO capacity agreement, respectively.

Atura is well positioned to continue to support Ontario electricity system's needs and expects to submit proposals for the IESO's upcoming LT2 procurement windows. [redacted] to Atura's proposals in the capacity stream of the initial procurement window under the LT2 RFP, to be submitted in December 2025. Successful proponents will receive 20-year contracts with the IESO, with results from the 2025 procurement window expected in the first half of 2026. Atura is in the process of developing the bids for this window in alignment with the Board's approval. [redacted]

Laurentis Energy Partners

LEP's capital portfolio consists of approximately [redacted] for development work during the business plan period, including a second TDS at Darlington Unit 3 to advance the production of medical isotopes. The main installation work on the system is expected to be executed in 2026, coinciding with the planned outage on the unit.

Nuclear Provision Expenditures



Planned expenditures against the previously established provision for nuclear decommissioning and management of nuclear wastes total approximately $5.9 billion over the 2025-2031 period. Expenditures for decommissioning and long-term disposal programs total approximately $3.6 billion and will be funded from the nuclear segregated funds. Expenditures for interim storage programs total approximately $2.3 billion and will be largely funded from operating cash flow. The segregated funds are established pursuant to the ONFA between OPG and the Province and, through a separate agreement between the CNSC, the Province and OPG, are used to satisfy OPG's financial guarantee requirements under the CNSC operating licences for the existing facilities.

The majority of decommissioning expenditures over the 2025-2028 period are for the execution of the Pickering safe storage project in order to achieve a safe storage state for Units 1 and 4 by 2028. The first phase of the project includes the scope required immediately following the units' shutdown such as defueling and dewatering of the reactors and associated system modifications and end-stating, as well as funding for functional support and other ongoing station costs. The defueling and dewatering of both reactors is planned to be completed in 2025. The second phase will complete all remaining longer-term activities necessary to enable the safe storage state. The first phase is tracking within the approved RQE, with the second phase funding request targeted for later in the business plan period.

Decommissioning expenditures also include ongoing costs to maintain Pickering Units 1-4 in a safe storage state in compliance with the applicable regulatory requirements after the safe storage project has been completed and to continue decommissioning planning activities throughout the business plan period. OPG received CNSC staff acceptance off its first detailed decommissioning plan (DDP) for Pickering Units 1-4 in June 2025. The business plan aligns to the DDP, which assumes a deferred decommissioning strategy. While no major dismantlement is planned at Pickering prior to the emptying of the wet bays beyond the business plan period, as contemplated by the DDP, the plan includes funding to allow select non-nuclear dismantlement to be advanced earlier for operational or strategic reasons. OPG will continue to periodically review the decommissioning strategy and update the DDP.

The planned long-term disposal program expenditures mainly reflect OPG's portion of funding for Nuclear Waste Management Organization's (NWMO) activities to advance Canada's Adaptive Phased Management (APM) used fuel disposal program. In November 2024, the NWMO announced that it had selected Wabigoon Lake Ojibway Nation and the Township of Ignace, Ontario as the host communities for the future site of Canada's DGR for used nuclear fuel under the APM. Forecasted funding is based on the NWMO's plan to progress the project through the regulatory approval and mobilization preparation phase, targeting completion of the federal Impact Assessment process by the end of the business plan period. The start of the used fuel DGR construction is anticipated beyond the business plan in the 2030s. The higher budgeted expenditures in 2025 reflect the finalization of the NWMO's hosting agreements for the selected used fuel site. The NWMO is also developing a consent-based site selection process for a DGR for intermediate-level waste, in alignment with a national integrated strategy for nuclear waste management endorsed by the Federal Government.

A key focus of OPG's interim storage programs continues to be initiatives to safely reduce the environmental footprint and lifecycle costs of low-level and intermediate-level waste. OPG continues to target reductions in the volumes of waste requiring storage and disposal through processing and recycling capability. Over the business plan period, the Company will continue to invest in existing and new solutions to help achieve these targets, such as waste sorting, resin processing and metal processing. Additionally, OPG's waste management operations are focused on ensuring readiness for the Pickering Refurbishment and DNNP operations.

The plan reflects the current reference plan under the ONFA, covering the 2022-2026 period, as approved by the Province in 2022. A reference plan contains OPG's comprehensive lifecycle cost estimates for nuclear decommissioning and waste management programs for the existing facilities and serves as the basis for the associated funding requirements to the nuclear segregated funds. Based on the current reference plan, the segregated funds are currently in a fully funded position requiring no additional overall contributions. ONFA reference plans are required to be prepared at least once every five years. The ONFA reference plan update process for the 2027-2031 period is underway and will be incorporated into future business plans, including the impact of the NWMO's next update of the cost estimate for the used fuel DGR. The updated reference plan will be subject to review and approval by the Province.

The ONFA currently covers OPG's existing nuclear facilities only. The Company is evaluating how it could satisfy the financial guarantee requirements that would apply under a future DNNP operating licence issued by the CNSC, including developing detailed estimates of decommissioning and waste management liabilities expected as a result of DNNP operations. The resulting impacts will be reflected in future business plans and are assumed to be subject to a regulatory deferral account.

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APPENDICES

1. Key Planning Assumptions
2. Key Risks
3. Financial, Headcount and Production Budget Information
4. Key Operational Targets
5. Environmental, Governance and Sustainability Overview

APPENDIX 1: KEY PLANNING ASSUMPTIONS

The key planning assumptions for the 2025-2031 business plan are outlined below:

Operations and Project Assumptions

Nuclear

- Refurbishment of Darlington Unit 4 is completed in the first half of 2026
- Continued commercial operation of Pickering Units 5-8 to September 2026, prior to refurbishment
- The first Pickering unit, Unit 5, returns to service from refurbishment in May 2031, with subsequent units progressing through overlapped execution
- The first DNNP unit enters commercial operation in October 2030 and subsequent units progress through execution following Unit 1 construction, all subject to requisite approvals including receipt of the CNSC operating licence for Unit 1
- DNNP Unit 1 refuelling outage takes place within 12 months of commencing commercial operation
- Generation plans for refurbished and new units include outage days for warranty activities
- The Darlington VBO, the Darlington Unit 2 turbine control and auxiliary systems upgrade and the Darlington Unit 2 primary moisture separator replacements take place in 2027
- Turbine rotor replacements are undertaken at the Darlington units in their respective planned outages beginning in 2029
- A sustaining capital project portfolio allocation for Pickering Units 5-8 restarts beginning in 2025 in support of planned post-refurbishment operations
- The plan includes initial non-capital planning and preparation costs for potential new nuclear generation; no capital expenditures or associated resources are included for such potential projects
- Current operating strategies continue at the Company's waste management facilities

Hydroelectric and Thermal

- Generation plans reflect Market Renewal Program assumptions and outage assumptions for the hydroelectric refurbishment and redevelopment programs. Major hydroelectric refurbishments during the period include units at the Sir Adam Beck generating complex and the R.H. Saunders and Otto Holden stations
- Coniston-Stinson and Bingham Chute hydroelectric redevelopments are completed in 2027; Kakabeka Falls and Matabitchuan hydroelectric redevelopments are completed in 2028
- Execution of a project to add an incremental generating unit at the Chats Falls hydroelectric station begins in 2029 and is completed beyond the business plan period
- The plan includes initial non-capital planning and preparation costs for potential new hydroelectric generation; no capital expenditures or associated resources are included for such potential projects
- Lennox continues to operate under a new five-year agreement with the IESO beginning in May 2029; Atikokan operates under the existing agreement with the IESO until 2029

Atura Power and Eagle Creek

- [redacted]
- The Napanee BESS and the Niagara Hydrogen Centre are completed in 2026, and the Napanee gas plant expansion is completed in 2028
- [redacted]
- [redacted]
- The sale of Eagle Creek is closed in the first quarter of 2026, with net proceeds of CAD [redacted]

Financial, Rate Regulation and Other Assumptions

- New nuclear and hydroelectric regulated rates are effective January 1, 2027, with a weighted average requested rate increase of up to 2.5% annually, on average, over the 2027-2031 period and based on the OEB's prescribed ROE value. The nuclear base rate is set based on the existing custom incentive ratemaking framework. The hydroelectric base rate is rebased in 2027 and thereafter is set using a price-cap index with the addition of a custom capital factor to support the need for ongoing capital investments
- A regulatory mechanism for concurrent cost recovery of debt financing costs during construction of the DNNP and the Pickering Refurbishment is in place by the beginning of 2026, with recovery beginning in 2027
- New nuclear and hydroelectric rate riders are effective January 1, 2027 to disposition most of the Company's deferral and variance account balances recorded as of December 31, 2024
- Consistent with proposed amendments to O. Reg. 53/05 published by the Province in April 2025, non-capital pre-development costs incurred for potential new hydroelectric facilities in Ontario are eligible to be recorded in a regulatory variance account for future recovery, subject to the OEB's review. In the absence of such mechanism, planned net income will be negatively impacted
- The Province is assumed to make equity injections in OPG totaling $5 billion over the 2025-2027 period (2025 – $1 billion, [redacted]).[1] Under the anticipated terms of the equity injection, associated dividends would be in-kind during the business plan period
- The DNNP partnership transaction with Canada Growth Fund and Building Ontario Fund, as non-controlling investors, closes by the end of 2025. The partnership will lease the assets from OPG, who will continue to be the CNSC licence holder, project manager and operator of the facility, and will reimburse OPG's costs incurred in performing these roles. The partnership will be a new rate regulated entity enabled by an amendment to O. Reg. 53/05, with a single base regulated rate established by the OEB for OPG's Pickering and Darlington facilities and the DNNP partnership
- Federal clean energy investment tax credits are not included in the plan unless they have been legislated into law at the time of writing and are applicable to the specific project technology. Federal clean energy investment tax credits are not included in the plan unless they have been legislated into law at the time of writing and are applicable to the specific project technology. Potential CEITCs are therefore excluded
- Interest rate for new general corporate long-term debt issuances is approximately 5%, assuming current credit ratings are maintained for the full business plan period
- Pension fund investments earn 6.25%/year. The discount rates for valuing accounting obligations for pension and other post-retirement benefits is approximately 5.0%. Based on the projected surplus status of the plan, OPG's contributions are limited to equal sharing with employee contributions for the full business plan period
- Nuclear segregated fund investments earn 5.15%/year
- Potential future changes in the tariffs/trade environment are not considered
- The current 2022-2026 ONFA reference plan is reflected for the duration of the business plan. The 2027-2031 ONFA reference plan update process is underway and will be incorporated into future business plans
- OPG will retain DNNP decommissioning and waste management liabilities. OPG is evaluating how it can satisfy the associated CNSC financial guarantee requirements for a future DNNP operating licence from the CNSC and developing detailed estimates of these liabilities. Resulting impacts will be reflected in future business plans and are assumed to be subject to a regulatory deferral account
- OPG continues to report financial results in accordance with US GAAP for the full business plan period
- Potential impacts from the 2025 Federal Budget are not reflected

[1] For 2025, equity injections are reflected in the forecast information but not the budget information.

APPENDIX 2: KEY RISKS

The key risks to the 2025-2031 business plan are outlined below:

Operational and Project Risks

- **Supply Chain Capacity:** Capacity constraints with key suppliers for goods and services may impede OPG's ability to maintain reliable operations and execute projects, including those associated with growth
- **Cyber Security:** Risk of cyber security incidents impacting availability, integrity or confidentiality of information systems and operations technologies
- **Vendor Performance and Key Trades Availability**: Risks related to vendor performance and key skilled trades availability could impact cost, schedule and quality of OPG's projects
- **Darlington New Nuclear Project:** Challenges with first-of-a-kind (FOAK) execution may lead to cost and schedule impacts beyond the Unit 1 approved plan
- **Pickering Refurbishment:** Risk that the Pickering Refurbishment may not achieve readiness to proceed to execution as planned, followed by execution risks to maintaining cost and schedule commitments and requisite quality, including a number of FOAK elements
- **Darlington Refurbishment:** Failure to maintain Darlington Refurbishment cost and schedule commitments, safely and with requisite quality
- **Talent:** Successful execution of major projects and growth initiatives and sustainment of existing operations may be challenged depending on OPG's ability to retain and attract qualified employees, including leadership roles
- **Labour Relations:** Collective bargaining risks as they relate to future labour agreements, including their impacts on operations and operating costs
- **Generation and Station Condition:** Risks of emergent or greater-than-planned work associated with unexpected asset aging or discovery of unexpected conditions may result in unplanned outages, unit de-rates or extension of planned outages
- **Environmental, Health and Safety:** Risks associated with a significant environmental non-compliance and/or employee and public health and safety incident occurring, including uncertainties surrounding obligations for environmental remediation costs
- **Climate Change:** Changing climate resulting in operational disruptions due to severe weather events or physical climate parameters beyond operating limits, and/or increased costs to ensure safe and reliable operations

Financial, Rate Regulation and Social Licence Risks

- **Tariffs/Trade Environment:** The instability of the current tariff and trade landscape could materially affect costs and schedules related to operations and projects, result in supply chain disruptions and/or alter OPG's supply chain strategies
- **Indigenous Relations:** Indigenous peoples or communities may not support OPG's operations or projects, including nuclear waste management
- **Government Policies, Regulations and Directives:** Setting or changing of government policy decisions can impact existing operations, planned or potential projects and growth initiatives, and funding mechanisms including the availability of federal clean energy investment tax credits; changes to legislation or regulations related to carbon intensity of electricity generation could affect long-term operation of certain assets
- **Nuclear Waste Approval:** Approval for long-term nuclear waste management facilities may be denied or delayed, resulting in continued interim storage cost and additional costs to identify new/alternate options
- **Economic Factors and Global Events:** Elevated construction and skilled labour costs may affect OPG's ability to achieve operating and project cost budgets; changes in interest rates or unfavourable capital markets conditions may increase OPG's borrowing costs or affect timing of debt issuances; volatility in market returns may affect OPG's pension and nuclear segregated funds' performance and future funding requirements; geo-political events could drive long-term implications for commodity, financial and electricity markets
- **Regulatory Risk:** Risks related to uncertainty or changes in rate regulation and OEB decisions and orders
- **Credit Ratings:** The costs of future debt issuances and projects may be negatively impacted in the event of a negative credit rating action

APPENDIX 3: FINANCIAL, HEADCOUNT AND PRODUCTION BUDGET INFORMATION

Key Financial Metrics [1]	*Budget*	*Forecast*	*Business plan*					
(millions of dollars, unless otherwise noted)	**2025**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Financial performance metrics								
Net income attributable to the Shareholder	[redacted]							
Earnings before tax								
Return on equity [2]								
Debt ratio								
FFO to total debt ratio (current threshold of 13%)								
CF to debt ratio (current threshold of 15%)								
Total debt at year-end								
Net cash from operations								
Cash balance at year-end								
Total capital assets								
Total return to Shareholder [3]								
Cost performance metrics								
OM&A expenses from ongoing operations (excl. operating subsidiaries)	[redacted]							
Nuclear Refurbishment and DNNP capital expenditures	2,883	3,618	4,979	5,318	5,203	5,135	5,042	4,241
Nuclear Refurbishment and DNNP in-service additions	26	38	2,460	23	-	-	6,585	9,610
Capital expenditures excluding Nuclear Refurbishments and DNNP	[redacted]							
Capital in-service additions [4]								
Nuclear provision expenditures	1,122	1,054	944	950	860	712	698	700

1. Financial information includes consolidation of DNNP partnership information in OPG's financial results. Financial information does not include the impact of Clean Electricity Investment Tax Credits.
2. Calculated as: net income attributable to Shareholder / average shareholder's equity excluding accumulated other comprehensive income.
3. Calculated as: net income attributable to Shareholder + income taxes in Ontario + gross revenue charge + property tax PILs.
4. Excludes [redacted] Nuclear Refurbishments and DNNP.

Consolidated Income Statement	*Budget*	*Forecast*	*Business plan*					
(millions of dollars, years ending December 31)	**2025**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Electricity generation revenue	[redacted]							
Fuel and gross revenue charge								
Generation sales gross margin								
Non-electricity generation gross margin								
Total gross margin								
OM&A expenses (excluding cost of goods sold)								
Depreciation and amortization								
Accretion on nuclear waste and other liabilities								
Earnings on nuclear funds								
Property taxes								
Total expenses								
Income before interest and other income								
Net interest expense								
Other expense [1]								
Income before tax								
Income tax								
Net income								
Net income attributable to the Shareholder								
Net income attributable to non-controlling interest								

[redacted]

OM&A Expenses	*Budget*	*Forecast*	*Business plan*					
(millions of dollars, years ending December 31)	**2025**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Operations base and outage								
Nuclear base	709	722	653	407	411	444	468	754
Nuclear outage incremental	127	133	209	224	113	219	122	191
Renewable Generation operations	[redacted]							
Enterprise Operations support	624	608	609	495	500	516	539	646
Enterprise Projects	18	22	15	11	12	12	12	13
Pickering cyclical maintenance [1]	-	-	25	168	161	169	170	107
	[redacted]							
Operations projects								
Nuclear	70	68	71	76	82	84	85	83
Renewable Generation	[redacted]							
	[redacted]							
Fuel Channel Life Extension and related costs	5	7	2	-	-	-	-	-
Total operations and projects (excluding operating subsidiaries)	[redacted]							
Support Services								
Corporate Services	367	368	383	393	401	420	434	467
Commercial Operations and Regulatory Affairs	58	58	64	67	62	65	69	78
Corporate Affairs, Enterprise Strategy and Law	59	57	62	57	58	61	64	65
Support Services Projects	36	37	47	51	48	47	46	44
	520	520	556	568	569	593	613	654
Total business unit expenditures	[redacted]							
Insurance	52	52	51	66	68	71	80	91
Other	[redacted]							
Total ongoing operations (excluding operating subsidiaries) [2]	[redacted]							
Other OM&A								
Eagle Creek Renewable Energy Atura Power	[redacted]							
Laurentis Energy Partners								
Other Subsidiaries								
Darlington Refurbishment	10	10	2	-	-	-	-	-
Pickering Refurbishment	9	-	4	100	94	85	53	47
DNNP operational readiness	6	13	29	46	46	42	46	15
New nuclear development	75	62	136	4	4	4	4	4
New hydroelectric development	[redacted]							
Small hydroelectric redevelopment	11	10	6	7	3	-	-	-
Centrally-held pension and OPEB	(192)	(180)	(210)	(194)	(212)	(225)	(224)	(227)
OEB deferral and variance account offsets	(224)	(174)	(856)	(19)	(19)	(16)	(19)	(23)
Other	[redacted]							
Total OM&A expenses								

1. Represents inspection, maintenance and other station work during refurbishment outages to ensure compliance with regulatory requirements and readiness to return the units to service.
2. Includes DNNP partnership.

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Consolidated Balance Sheet *(millions of dollars, as at years ending December 31)*	*Budget* **2025**	*Forecast* **2025**	*Business Plan* **2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Assets								
Current assets								
Cash and cash equivalents								
Equity securities								
Accounts receivable								
Fuel inventory								
Materials and supplies								
Other current assets								
Property, plant and equipment and intangible assets (net)								
Other assets								
Loan receivable								
Nuclear fixed asset removal and nuclear waste management funds								
Long-term materials and supplies								
Regulatory assets (net)								
Investments subject to significant influence								
Pension assets								
Goodwill								
Other long-term assets								
Total Assets								
Liabilities								
Current liabilities								
Short-term notes payable								
Accounts payable and accrued charges								
Long-term debt due within one year								
Long-term debt								
Other liabilities								
Fixed asset removal and nuclear waste management liabilities								
Other post-employment benefit liabilities								
Pension liabilities								
Long-term accounts payable and accrued charges								
Deferred revenue								
Deferred income taxes								
Equity								
Class A shares								
Common shares								
Preferred shares								
Contributed surplus								
Retained earnings								
Accumulated other comprehensive loss								
Equity attributable to non-controlling interests								
Total Liabilities and Equity								

Consolidated Financing and Liquidity Outlook	*Budget*	*Forecast*	*Business Plan*					
(millions of dollars, years ending December 31)	**2025**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Opening cash balance	**1,247**	**1,363**	**801**	**930**	**941**	**938**	**933**	**937**
Operating activities								
Net operating cash inflows before the following:								
Interest paid								
Interest capitalized								
Pension plan contribution								
OPEB payments								
Internally-funded nuclear provision expenditures								
Cash flow provided by operating activities								
Investing activities								
Capital expenditures								
OPG sustaining capital (excl. subsidiaries) [1]								
Darlington Refurbishment	(895)	(835)	(392)	-	-	-	-	-
Pickering Refurbishment	(970)	(1,500)	(2,954)	(3,668)	(3,677)	(3,480)	(2,628)	(1,859)
Darlington New Nuclear Project	(1,018)	(1,283)	(1,633)	(1,650)	(1,527)	(1,654)	(2,414)	(2,382)
OPG subsidiaries								
Other development								
Net proceeds on sale of Eagle Creek								
Other								
Cash flow used in investing activities								
Financing activities								
Long-term debt								
Debt issuance								
Debt retirement								
Province equity injections	-	1,000						
Short-term notes net (repayment) issuance								
Net contribution from DNNP partnership non-controlling interests	-	676	323	278	289	328	468	349
Net contribution from (net distribution to) other non-controlling interests								
Cash flow provided by financing activities								
Effects of exchange rate changes								
Net cash (outflow) inflow for period								
Ending cash balance								
Total OPG consolidated debt								

1. Excludes the Pickering Water Treatment Plant, which is included in the Capital Expenditures table as an addition to capital assets but will be accounted for as a finance lease arrangement and therefore has no investing cash flow impact.

Production	*Budget*	*Forecast*	*Business Plan*					
(TWh, years ending December 31)	**2025**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Darlington	21.1	21.5	21.1	18.7	26.7	25.1	26.8	27.1
Pickering	15.9	16.1	11.4	-	-	-	-	1.9
DNNP	-	-	-	-	-	-	0.5	1.9
Total Nuclear	37.0	37.6	32.5	18.7	26.7	25.1	27.3	30.9
Regulated Hydroelectric	31.9	31.7	31.7	31.5	31.5	32.0	32.1	32.1
Contracted Hydroelectric & Thermal								
Atura Power								
Total Ontario production (net of SBG losses)								
Regulated Hydroelectric SBG losses	(1.1)	(0.9)	(1.1)	(1.0)	(1.2)	(1.0)	(0.9)	(0.8)
Contracted Hydroelectric SBG losses								
Total SBG losses								
Eagle Creek Renewable Energy								

Headcount [1]	*Budget*	*Forecast*	*Business Plan*					
(years ending December 31)	**2025**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Enterprise Operations								
Nuclear operations	2,761	2,831	1,305	1,276	1,257	1,259	1,328	2,382
Renewable Generation operations								
Enterprise Operations support	3,543	3,353	3,451	3,427	3,459	3,404	3,498	3,507
Enterprise Projects								
Support Services								
Corporate Services [2]	1,399	1,348	1,364	1,369	1,363	1,360	1,368	1,365
Commercial Operations and Regulatory Affairs	395	388	395	394	392	389	386	374
Corporate Affairs, Enterprise Strategy and Law	182	183	196	187	186	185	182	175
	1,976	1,919	1,955	1,950	1,941	1,934	1,936	1,914
Ontario Subsidiaries								
Atura Power								
Laurentis Energy Partners								
PowerON Energy Solutions								
Total Ontario-based headcount								

1. The organizational view shown above includes DNNP and Pickering Refurbishment in respective organizations.
2. Corporate Services includes Corporate & Technology Services, Real Estate, Finance, and Human Resources.

Nuclear Provision Expenditures	*Budget*	*Forecast*	*Business Plan*					
(millions of dollars, years ending December 31)	**2025**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Used fuel and low and intermediate level waste disposal	520	466	328	337	345	300	292	294
Used fuel and low and intermediate level waste interim storage	309	288	360	343	339	336	325	322
Decommissioning	293	300	256	270	176	76	81	84
Total nuclear provision expenditures	**1,122**	**1,054**	**944**	**950**	**860**	**712**	**698**	**700**

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Capital Expenditures	*Budget*	*Forecast*			*Business Plan*			
(millions of dollars, years ending December 31)	**2025**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Sustaining Capital								
Nuclear								
Nuclear Project Portfolio	422	420	499	562	509	524	501	484
Darlington SG Primary Moisture Separators	40	40	81	101	13	-	-	-
Darlington Turbine Rotor Replacements	42	42	162	241	322	519	408	308
TRF Major Component Replacement	25	25	36	54	33	57	30	18
Darlington U2 Turbine Control & Aux. System	17	17	28	66	4	-	-	-
Darlington U1 and 2 Generator Stator Rewind	7	7	41	16	112	30	93	1
Darlington Non-Routine SG Cleanings	9	9	14	13	12	9	-	-
Pickering Water Treatment Plant	-	-	-	-	-	-	98	-
Nuclear Refurbishment New Fuel	20	20	-	-	-	-	24	25
DNNP Capitalized Fuel	-	-	-	-	-	-	78	29
	582	580	861	1,053	1,005	1,139	1,232	865
Regulated Hydroelectric								
Regulated Hydroelectric Project Portfolio	286	311	281	283	334	305	334	333
Regulated Hydroelectric Refurbishments	244	217	340	409	487	427	465	406
Regulated Hydroelectric Redevelopments [1]	312	283	355	157	18	1	-	-
Abitibi Canyon Concrete and Sluiceway Rehab.	20	17	2	10	54	132	166	180
Sir Adam Beck Power Canal Infrastructure	6	7	5	18	21	134	2	-
	868	835	983	877	914	999	967	919
Contracted Hydroelectric and Thermal								
Smoky Falls Dam Safety	[redacted]							
Other Contracted								
Support Services								
Corporate Technology Services Project Portfolio	81	87	155	183	149	136	136	122
DNNP Operational Readiness Tech. Projects	-	24	36	28	23	20	16	19
Real Estate Project Portfolio	19	36	77	102	42	43	48	31
Corporate Headquarters Renovation	72	81	-	-	-	-	-	-
	172	228	268	313	214	199	200	172
Total OPG Sustaining Capital (Excl. Subsidiaries)	[redacted]							
DNNP Unit 1 and Common Scope	1,004	1,216	1,455	1,410	897	305	373	-
DNNP Units 2-4 [2]	14	67	178	240	630	1,349	2,041	2,382
Darlington New Nuclear Project (DNNP)	1,018	1,283	1,633	1,650	1,527	1,654	2,414	2,382
Pickering Refurbishment	970	1,500	2,954	3,668	3,677	3,480	2,628	1,859
Darlington Refurbishment	895	835	392	-	-	-	-	-
Chats Falls Hydroelectric Expansion	-	-	1	4	6	26	34	28
Atura Power	[redacted]							
Eagle Creek Renewable Energy								
Laurentis Energy Partners								
PowerOn Energy Solutions								
Other								
Total Capital Expenditures								

1. Regulated Hydroelectric Redevelopments include the Kakabeka Falls, Coniston and Stinson, Matabitchuan and Bingham Chute projects.
2. Includes expenditures of $455 million for the business plan period that are covered by existing Board approved funding releases.

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APPENDIX 4: KEY OPERATIONAL TARGETS

Nuclear Targets [1]

			Pickering								*Darlington*							
			Budget	Forecast	*Business Plan*						Budget	Forecast	*Business Plan*					
Metric	**NPI Max**	**Industry Top Quartile**	**2025**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2025**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Collective Radiation Exposure *(person-rem/unit)* [2]	80.0	41.8	59.3	59.3	41.82	N/A	N/A	N/A	N/A	45.30	25.6	25.6	66.8	67.3	47.9	73.3	44.0	45.8
Unit Capability Factor *(%)* [2]	94.0	90.9	89.1	89.5	87.0	N/A	N/A	N/A	N/A	68.2	94.2	94.2	76.0	62.9	88.6	83.5	88.6	88.7
Forced Loss Rate *(%)* [2,3]	1.0	0.8	3.5	3.5	3.5	N/A	N/A	N/A	N/A	12.0	3.6	3.6	3.5	2.9	2.2	2.0	2.0	2.0
On-line Corrective Maintenance Backlog *(work orders/unit)* [2]	N/A	0	0	0	0	N/A	N/A	N/A	N/A	1	0	0	0	0	0	0	0	0
WANO NPI (Index) [2]	85.0	98.3	78.4	82.7	81.8	N/A	N/A	N/A	N/A	N/A	87.8	80.2	82.1	92.2	92.3	91.6	93.1	93.6
Human Performance Error Rate	0.000	0.000	0.000	0.000	0.000	N/A	N/A	N/A	N/A	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Generating Cost (Annual) *($ per MWh)* [4,5]	N/A	30.7	31.6	31.4	39.0	N/A	N/A	N/A	N/A	N/A	34.7	34.5	42.3	51.6	41.1	42.2	39.1	34.7

Renewable Generation Targets (Ontario)

	Budget	*Forecast*	*Business Plan*					
	2025	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Capacity (MW) [6]	[redacted]							
Regulated Hydroelectric	6,572	6,572	6,579	6,592	6,616	6,640	6,644	6,644
Contracted Generation (Hydro, Thermal and Solar)	[redacted]							
Hydroelectric Availability (%)								
Regulated Hydroelectric	87.5	87.2	87.4	83.8	83.7	84.9	84.4	83.7
Contracted Hydroelectric	[redacted]							
Hydroelectric Equivalent Forced Outage Rate (%)								
Regulated Hydroelectric	3.2	3.2	3.6	3.6	3.6	3.6	3.6	3.6
Contracted Hydroelectric	[redacted]							
Thermal Equivalent Forced Outage Rate (Operating) (%)								

Atura Power Targets [7]

	Budget	*Forecast*	*Business Plan*					
	2025	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Capacity (MW)	[redacted]							
Thermal Availability (%) [8]								
Start Reliability (%)								

OPG Targets

	Budget	*Forecast*	*Business Plan*					
	2025	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Employee Safety [9]								
Serious Injury Incidence Rate (#/200k hrs worked)	0.02	-	0.01	0.01	0.01	0.01	0.01	0.01
Total Recordable Injury Frequency (#/200k hrs worked)	0.22	0.22	0.21	0.21	0.21	0.21	0.21	0.21
Environment [9]								
Total Recordable Environmental Events (#) [10]	32	12	15	15	15	15	15	15
Environmental Penalties or Fines (#)	-	-	-	-	-	-	-	-

1. Appropriate performance measures and targets for the DNNP units will be developed as they approach commercial operation.
2. Excludes units during the period they are undergoing refurbishment.
3. Includes a temporarily higher forced loss rate for Darlington units upon return to service following refurbishment, based on industry experience, prior to transitioning to normal operations with a 2.00% forced loss rate.
4. Consistent with industry definition metrics, excludes centrally-held pension and OPEB costs, asset service fees, used fuel expenses and certain developmental projects and related capital interest. Targets are normalized for refurbishment and technology, including outage duration impacts. Targets are indicative and will be updated once cost allocations and assumptions are finalized.
5. Given the significant diseconomies of scale associated with a single online unit for a partial year, OPG does not expect Pickering TGC's to be a meaningful measure of performance during 2031.
6. The planned generation capacity targets are based on estimates and the final capacity may differ once required engineering assessments have been completed and verified.

[redacted]

9. Represents corporate performance targets.
10. Includes Category A, B and C Spills, and Environmental Infractions.

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APPENDIX 5: ENVIRONMENTAL, GOVERNANCE AND SUSTAINABILITY OVERVIEW

OPG is committed to maintaining high standards of public health and safety and corporate citizenship, including environmental stewardship, transparency, community engagement and Indigenous relations. The Company strives to be a leader in advancing reconciliation with Indigenous peoples.

Safety and Environment

OPG is committed to high standards of public and workplace safety, including continuing to operate all facilities in a safe, secure and reliable manner. Over the business plan period, OPG will continue to maintain a strong focus on nuclear safety programs, invest in nuclear safety systems and dam and waterway safety upgrades, and foster public awareness regarding water safety. OPG will also continue to set aggressive internal workplace safety targets to drive continuous improvement across the organization toward the ultimate goal of zero injuries. OPG will continue to maintain planning, operational control and monitoring programs to manage its impact on the environment by meeting legal requirements and voluntary commitments. This includes preventing significant environmental events and keeping radiological emissions as low as reasonably achievable. OPG is also committed to developing and implementing climate change adaptation and mitigation strategies to ensure the safe, reliable, and cost-effective operation of its generating fleet. Key safety and environment targets can be found in **Appendix 4**.

Indigenous Relations

OPG is committed to working with Indigenous communities to continue fostering positive and mutually beneficial relationships that will create social and economic benefits through partnership and collaboration. OPG's Indigenous Relations Policy and Reconciliation Action Plan formalize the Company's commitment in this area and will continue to guide the Company's efforts over the business plan period. This includes undertaking proactive and ongoing engagement with Indigenous communities in relation to the Company's operations and projects, and pursuing new generation-related development partnerships on the basis of long-term commercial arrangements.

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2025-2031 Business Planning Schedule and Assumptions

Issued by:
Finance – Corporate Business Planning

February 2025

ONTARIO POWER GENERATION

CONTACT INFORMATION
If you require further information on business planning assumptions, schedules or requirements, please contact: Archana Srijeyanathan – Senior Manager, Financial Forecasts Michael Harwood - Director, Business Planning & Reporting

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1.0 BUSINESS PLANNING CYCLE SNAPSHOT

1.1 PLANNING CONTEXT

Energy transition policies, economic development and electrification continue to drive growing demand for electricity generation in Ontario. In October 2024, the IESO released an updated electricity demand forecast, which shows that Ontario's demand for energy is anticipated to grow by 75 percent leading up to 2050. Following the IESO's announcement and building on its Powering Ontario's Growth plan published in 2023, the Province of Ontario ("the Shareholder") released the Ontario's Affordable Energy Future: The Pressing Case for More Power document and subsequently introduced the Affordable Energy Act. These documents outline the Shareholder's vision for meeting the growing demand for energy in Ontario and ensuring Ontario is positioned to build the electricity generation, storage and transmission necessary to maintain a reliable electricity system over the long-term, while creating opportunities for becoming a continental leader in energy. Consistent with this vision, OPG is committed to playing a key role in responding to the growing need for electricity while maximizing value to the Shareholder, which is anchored in the Company's strong core operations and leveraging of assets and expertise to generate new growth opportunities.

OPG is well positioned to build new generating capacity across a range of technologies to meet Ontario's growing energy needs. This includes new natural gas-fired generation in the near term, which is needed to provide grid reliability and affordability and act as a bridging fuel, and the build out of nuclear, hydroelectric and new zero-emission technologies in the longer term. This also includes completing the Darlington Refurbishment project on time and on budget, proceeding with the execution of a small modular reactor (SMR) at Darlington (DNNP), enabling the continued operation of the Pickering Nuclear Generating Station Units 5 through 8 (Pickering Units 5-8) commercially through 2026, planning for the refurbishment of these Pickering units, executing the hydroelectric major overhauls program and investments in existing facilities through sustaining capital and operational programs. Building on Ontario's decades of experience, OPG expects that investments in nuclear and hydroelectric capacity will continue to set the path for cost effective, reliable and clean energy in the province through 2050 and beyond.

The 2025-2031 Business Plan ("Business Plan") is expected to underpin OPG's upcoming application to the Ontario Energy Board ("OEB") to set the Company's regulated rates covering the 2027-2031 period. OPG expects to seek approval of the Business Plan and subsequently file an application to the OEB for new regulated rates in the latter half of 2025.

1.2 SCHEDULE

CONTACT: ARCHANA SRIJEYANATHAN

The schedule of key activities for the current business planning cycle is provided below. The schedule reflects a targeted date for Board of Directors' review and approval of the Business Plan. The timelines for various activities, including Business Unit (BU) submission deadlines and executive level reviews, have been set accordingly.

Business planning activities require significant coordination among organizations. The same planning information may be used by different users at various times throughout the business planning process. It is critical to the integrity of the consolidated OPG plan that information provided to different business planning users be consistent.

Date	Deliverable	Accountability
January 10, 2025	Template for CEO review presentations provided. More details in section 2.1.3.	Corporate Business Planning
February 7, 2025	Headcount updated in Workforce Planning Tool.	All business units into Workforce Planning Tool
February 7 to February 14, 2025	Sign-offs on budget transfers between business units (BUs) in MS Forms. More details in section 2.6.	All business units to Corporate Business Planning via MS Forms
	BU submission of updates to inputs to the Energy Production and Revenue Plan. More details in section 2.2.	Generation & Revenue Planning
	Identification and communication of annual resources for inter-business unit service needs with signed service level agreements (SLAs) provided to respective Controllership organization via MS Forms. More details in section 2.6.	All business units with indication of sign-off to Corporate Business Planning and submission of SLAs via MS Forms.
	Submission of fuel inventory continuity.	Nuclear Controllership to Corporate Business Planning
	Calculations of nuclear fuel bundles (Darlington and Pickering only). More details in section 2.1.1.	Supply Chain to Actuarial Group and Life Cycle Liability Management Group
	BUs submit planned contract revenue cost inputs. More details in section 2.2.	All business units to Commercial Market Strategy
	Submission of Nuclear provision funding and headcount. More details in section 2.1.5.	Nuclear Finance Controllership and Corporate Controllership to provide to Nuclear Liability Provision Management
	Property tax expense (separately showing amounts to be charged to nuclear and thermal decommissioning provisions).	Corporate Real Estate to Corporate Business Planning
February 21, 2025	Submission of materials and supplies continuity.	Nuclear and RG Controllership to Corporate Business Planning

Date	Deliverable	Accountability
	BU submissions of BPC planning input. More details in section 2.5.	All business units to Corporate Business Planning
	Submission of business plans by self-sustaining subsidiaries. More details in section 2.3.	Subsidiaries – Business Integration to Corporate Business Planning
	Submission of inputs for income attributable to non-controlling interest. More details in section 2.3.	RG Controllership – Central to Corporate Business Planning
	Submission of cost allocations for Support Services and Operations Support. More details in section 2.1.4.	Corporate Controllership and Operations Support Controllership to Finance – BUS Team
	Provision dollar amount for nuclear used fuel costs (see 2.1.1)	Nuclear Lifecycle Liability Management team to Nuclear Finance Controllership
February 28, 2025	Submission of Energy Production and Revenue Plan. More details in section 2.2.	Generation & Revenue Planning to Corporate Business Planning
	Submission of supplementary financial information, analyses, and reconciliations including plan-over-plan, and year-over-year analyses. More details in section 2.1.b.	All business units to Corporate Business Planning
	Review of contract revenue plans. More details in section 2.2.	Finance staff
	Submission of project portfolio listings, supporting planning BCS or equivalent documentation.	All business units to BU Controllers and Corporate Business Planning
	Submission of nuclear asset retirement obligation, accretion, and nuclear segregated funds balance projection.	Nuclear Liability Provision Management to Corporate Business Planning
	Input final updates and changes into BPC based on feedback from Corporate Business Planning.	All business units to Corporate Business Planning
March 7, 2025	Finance reviews and sign-offs. More details in section 1.2.1.	All business units to Corporate Business Planning

Date	Deliverable	Accountability
	Submissions of corporate level information including employee incentive costs and other centrally-held costs. More details in sections 2.4.a to 2.4.h.	All business units to Corporate Business Planning
	Preliminary BUS run and review	Finance – BUS Team
	Submission of inputs for income attributable to non-controlling interest. More details in section 2.3.	RG Controllership – Central to Corporate Business Planning
March/April 2025	Finalize and submit monthly trending in BPC system.	All business units to Corporate Business Planning
	CEO reviews of BU business plans.	All business units
May 5, 2025	Consolidated OPG business plan submitted to Board of Directors'.	Corporate Business Planning
June 2025	Finalization of cost allocations (as required) and loading of budgets into reporting systems.	Finance – BUS Team
June 2025	Conversion of planning information to Shareholder's fiscal basis.	Corporate Business Planning

1.2.1 Finance Review and Sign-off

CONTACT: ARCHANA SRIJEYANATHAN

The following senior Finance staff will complete and submit to Corporate Business Planning a financial review and sign-off for the applicable business planning submissions:

Date	Deliverable	Accountability
March 7, 2025	Submission of OM&A expenses, capital expenditures, and in-service amounts, provision expenditures, and non-generation revenue.	BU Controllers
	Review / signoff of contract generation/capacity revenue calculations.	Jointly by Director, RG Controllership, Director, Generation & Revenue Planning, and Director, Business Planning

Date	Deliverable	Accountability
	Review / sign-off of depreciation & amortization (excluding amortization of deferral and variance accounts) and centrally-held costs per section 3.5.	Senior Manager, Corporate Accounting and Policy
	Review / signoff of nuclear decommissioning and waste management obligations.	Jointly by Director, Controllership and Senior Manager, Actuarial & Financial Evaluations
	Review / signoff of pension and OPEB assumptions, calculations and accounting treatment.	Jointly by Director, Controllership and Senior Manager, Actuarial & Financial Evaluations
	Review / signoff of deferral and variance account assumptions, calculations and accounting treatment.	Director, Regulatory Finance

Sign-offs by the Director, Taxation on income taxes and the Assistant Treasurer for treasury inputs will be requested as required.

The sign-off will confirm that the Finance staff have reviewed the planning submissions and agree with the following in respect of the submissions, as applicable, taking into account the nature of the item, risk of error, materiality, degree of judgment required, and the complexity of underlying accounting:

- Appropriateness and consistency of financial/economic assumptions and calculations and their compliance with applicable contractual, legal and regulatory requirements, and OPG governance;
- Compliance with US Generally Accepted Accounting Principles (GAAP), including:
    - Planned costs have been appropriately classified as capital, OM&A or provision expenditures in the appropriate period;
    - Consistency of US GAAP application and any material implications of known or anticipated accounting policy changes;
    - Derivative financial instruments have been identified and appropriately recognized/valued;
    - Planned contractual milestone accruals have been budgeted in the appropriate period;
    - Underlying assumptions and valuations for provisions included in the plan are based on appropriate measurability and probability of occurrence criteria; and
    - Valuation of materials and supplies inventory is appropriate;
- Completeness and accuracy of the financial submissions based on known or anticipated operational decisions or assumptions;
- Inputs into calculations of planned contract generation/capacity revenue and deferral and variance account impacts are consistent with costs and other planning submissions;
- Basis of investment decisions identified in the plan and review of planning BCS or equivalent documentation for the projects included in the plan; and
- Compliance with these business planning instructions.

The sign-off process will be completed through a Microsoft Form sent directly to designated contacts.

1.3 OPERATING AND OTHER PLANNING ASSUMPTIONS

CONTACT: ARCHANA SRIJEYANATHAN

The following assumptions form the basis for the 2025-2031 Business Plan:

2025-2031 Business Plan Assumptions	
Pickering Operations	• End of life for Pickering Units 5-8 on September 30, 2026. • Maintenance and operating activities support the safe and reliable operation of the units with outages planned to facilitate operations through the planned end of life dates. • The SAFSTOR project transitioned to execution phase in 2024 after Pickering Unit 1 was taken offline. SAFSTOR project scope only includes Units 1 and 4. • Pickering Units 5-8 transition to Pickering Refurbishment once shutdown in September 2026, with Defuel, Dewater, Layup and Execution activities commencing
Pickering Refurbishment	• Pickering Units 5-8 refurbished subject to requisite approvals from the Board and concurrence from the Shareholder. • Pickering GS Unit 5 is returned to service in 2031 with planning, preparation and procurement activities undertaken accordingly, as appropriate.
Darlington Operations	• Outage plans and plant investments take into consideration life cycle plans and regulatory requirements and commitments and are aligned with unit refurbishments. • Unit 2 Turbine Generator Controls replacement outage is scheduled in 2027. • Final SG Primary Moisture Separators Replacements completed in 2027. • Vacuum Building Outage executed in 2027. • Post-refurbishment unit forced loss rate performance reflects industry operating experience.
Darlington Refurbishment	• The final unit is assumed to be complete in 2026.
Darlington New Nuclear Project	• OPG obtains all necessary approvals (including CNSC licence) to commence a capital construction project in early 2025. • Construction activities start early 2025 with the first unit in service in 2030.
Nuclear Sustainability Services	• A waste minimization and reduction program continues to be implemented. • Loading of dry storage containers is maintained at Darlington and at the Pickering Waste Management Facilities, and proceeds at a sustainable level for Bruce Power. • Used fuel and L&ILW volumes from the Bruce units are based on information received from Bruce Power; receipt of feeder waste from Major Component Replacement (MCR) for Bruce Unit 3 is underway and Unit 4 begins in 2025. • The long-term management of used nuclear fuel is consistent with the NWMO's Adaptive Phased Management program.
New Nuclear	• In November 2024, the Ontario government asked OPG to begin discussions with Indigenous, community and municipal leaders on its existing sites in Port Hope, Haldimand County and St. Clair Township (Wesleyville GS, Nanticoke GS and Lambton GS respectively) to determine community support for all types of new energy generation, including nuclear, to meet Ontario's soaring demand for electricity • OPG begins early planning and siting work for additional potential new nuclear build elsewhere in Ontario, as well as preliminary public and Indigenous engagement

2025-2031 Business Plan Assumptions	
	• OPG also begins support of new nuclear in Saskatchewan and Alberta, and other international jurisdictions including Poland, UK, and beyond through Laurentis Energy Partners.
Major Hydroelectric (Development)	• The major sustaining capital projects will include: o The Coniston-Stinson redevelopment commenced construction in 2024, with completion targeted in 2027. o The Kakabeka Falls redevelopment commenced construction in 2024, with completion targeted in 2028. o The Matabitchuan redevelopment will commence construction in 2025, with completion targeted in 2028. o The Bingham Chute redevelopment will commence construction in 2025, with completion targeted in 2027. o The Chat Falls upgrade program will commence engineering design in 2025, with critical system replacement taking place in 2029 for the first unit. The in-service dates of the units are outside the planning period.
Hydroelectric (Sustaining)	• Cyclical major unit refurbishments are planned using a condition and risk-based approach. • Smoky Falls Dam Safety is completed [redacted] • Abitibi Canyon upstream concrete project begins in 2028 and is in-service by the end of 2031. • Aguasabon Dam Rehabilitation project is completed by 2031. • Niagara Canal initiation and planning work occurs over 2025-2029.
Thermal	• Lennox GS continues operations under current contract for the business plan period until contract expiry (LESA expires April 30, 2029). • [redacted]
Real Estate	• Corporate Headquarters (CHQ) occupancy takes place in summer of 2025. • Steps continue to be taken to reduce and consolidate the real estate footprint, with certain leases not renewed during the planning period.
Information Technology	• Investments continue to be made in digital solutions and infrastructure as enablers of productivity and performance improvement initiatives. • Digital Strategy costs, including cyber security and automation, are planned by the Corporate and Technology Services (CTS) organization.
Nuclear Segregated Funds and Nuclear Liabilities	• Investments in nuclear segregated funds earn 5.15%.
Climate Change Considerations	• The cost of carbon and associated fuels will increase due to the Canadian federal carbon tax. [redacted] • Adaptation and carbon reduction costs will be identified an allocated by BU organizations in project and O&M plans.
Accounting Service Lives of Nuclear Stations	• The business plan will reflect current accounting end-of-life dates as approved by Depreciation Review Committee.
Inflation	• The preliminary targets are inclusive of changes to standard labour rates and assume a 2.5% inflation rate for purchased services and materials costs.

<table>
<tr><th colspan="2">2025-2031 Business Plan Assumptions</th></tr>
<tr><td></td><td>
• Recent market trends indicate that inflation for certain materials, equipment and services exceeds this range and such the following assumptions have been proposed:
<table>
<tr><th>Inflation Assumptions</th><th>Funding Area: Capital</th><th>Funding Area: OM&A</th></tr>
<tr><td>Labour</td><td>Use SLR rates found in BPC</td><td>Use SLR rates found in BPC</td></tr>
<tr><td>Procurement</td><td>Indexing based on existing contracts or supplier estimates. If indexing based on contracts or supplier estimates are unavailable, use 4.5% per year.</td><td>Indexing based on existing contracts or supplier estimates. If indexing based on contracts or supplier estimates are unavailable, use 4.5% per year.</td></tr>
<tr><td>Vendor trades</td><td>Use EPSCA SLR rates in BPC</td><td>Use EPSCA SLR rates in BPC</td></tr>
<tr><td>Professional Services</td><td>Assume 2.5% per year</td><td>Assume 2.5% per year</td></tr>
</table>
</td></tr>
<tr><td>Interest Capitalization Rules</td><td>
• Non-project specific (i.e. corporate borrowing funded) interest capitalization rates over the planning period are as follows:

2025: 3.95%
2026: 4.25%
2027-2031: 4.75%

• Projects that have specific financing associated with it (i.e. project financing) interest capitalization rates are to be derived in consultation with Treasury.
• The Pickering Refurbishment project and DNNP uses the above stated rates until 2026 and then 5% for 2027 onwards to reflect the long term nature of the project estimates.
• The Darlington New Nuclear Project uses the rates in the CIB loan until $970M is utilized and then the above states rates are used.
</td></tr>
<tr><td>Clean Electricity Investment Tax Credit (ITC)</td><td>• The Canadian federal government announced a refundable Clean Electricity Investment Tax Credit (ITC) for eligible investments. These ITCs are expected to be applicable to clean projects including SMR and certain hydroelectric projects. OPG is continuing to monitor developments in this area for consideration of impacts to its growth. If progressed, planning for such incentives will be held centrally.</td></tr>
<tr><td>Foreign Exchange Rates</td><td>• USD/CAD foreign exchange rate of 1.35 applies to transactions over the planning period.
• Foreign exchange rate for translation of Eagle Creek business plan to be determined through the business plan process.</td></tr>
</table>

1.3.1 Collective Agreements and Strategic Resourcing

OPG's current collective agreement with the Power Workers' Union (PWU) was renewed at the end of 2024 and expires on March 31, 2027. The collective agreement with the Society of United Professionals (Society) was renewed at the end of 2023 and expires on December 31, 2025. Due to inherent uncertainties in future collective bargaining outcomes, the budget will continue to be based on applicable existing collective agreement provisions and purchased services agreements. Please contact **Jon Wolfe** or **Niloufar Arshadi** in Labour Relations with any questions.

OPG's staffing strategies are developed with consideration of the operational programs and cost structures required to maintain strong performance of the Company's existing generating fleet and key projects, taking

into account workforce demographics and anticipated electricity system needs. In view of the heightened focus on energy transition and an increasingly competitive labour market for such resources, OPG's priority is to accelerate investment in talent attraction, development and retention for key skillsets and roles necessary to enable current and potential future projects and operations. The HR Workforce Planning team will provide BU Controllers and HR Business Partners with workforce planning analysis and tools to assist in evaluating and cost effectively addressing staffing needs. Please contact **Chris Mallinos** (Workforce Planning) for further information.

1.4 RESOURCE TARGETS

CONTACT: WEI SONG / ARCHANA SRIJEYANATHAN

Resource targets for the 2025-2031 Business Plan include ***Operating OM&A, Project OM&A and Sustaining Capital***. The targets are based on the assumptions outlined in section 1.3. Material developments affecting planning assumptions may necessitate revisions to the targets.

Operating OM&A targets reflect OPG's ongoing commitment to operational excellence and customer value while maximizing value to the Shareholder. This is anchored in the Company's strong core operations, while ensuring that there is no adverse impact to the safety, reliability and environmental sustainability of operations. This includes ensuring appropriate resourcing leading up to the execution phase of the Darlington New Nuclear project and the planned refurbishment of Pickering units 5-8.

Project OM&A targets are aimed at continuous improvement of project outcomes and forecast accuracy in support of effective management of the Company's capital investment portfolio.

Business Unit Operating OM&A, Project OM&A and Sustaining Capital Targets for the 2025-2031 Business Plan, are available in BPC, version G01.

1.4.1 Targets for Nuclear Waste Management and Decommissioning Expenditures

CONTACT: GARRY LAM / TINA MA

Provision project expenditures on nuclear waste management and decommissioning activities and all operating expenditures for these activities will be provided by Nuclear Liability Provision Management in a separate communication.

2.0 BUSINESS PLANNING AND BUDGETING INSTRUCTIONS

2.1 BUSINESS UNIT INFORMATION SUBMISSIONS

CONTACT: ARCHANA SRIJEYANATHAN

Business planning submissions are required from each BU for each of the year of the business plan by the dates specified in the business planning schedule (see section 1.2). The submissions will reflect the following reporting segment structure for the Company:

- Regulated – Nuclear Generation
- Regulated – Nuclear Sustainability Services
- Regulated – Hydroelectric Generation
- Contracted Hydroelectric and Other Generation
- Other

Further details on cost allocations, including for Operations Support facilities, are discussed in section 2.1.4.

BUs will use BPC to submit the majority of financial and headcount information. All other information will be submitted through email to the Business Planning & Reporting email address: FPA@ontariopowergeneration.onmicrosoft.com.

Each of the self-sustaining subsidiaries is required to submit a comprehensive business plan, as discussed further in section 2.4.

The BU submissions should include the following:

2.1.a Quantitative resource and financial information

- Submitted through the BPC system, in accordance with section 2.5.
- By Responsibility Centre (RC) and Resource Type (RT), in line with the direction provided in sections 2.1.4, 2.3, and 2.6.
- The submission must contain summarized monthly detail for 2026-2027, with added emphasis on forecast accuracy for the first quarter of each year (for Shareholder's fiscal year-end purposes) and annual information for the remaining years.
- Any changes to planning submissions after the BU submission deadline of **February 28, 2025** must be reported to, and confirmed with Corporate Business Planning.

2.1.b Supplementary financial information and supporting detailed year-over-year, plan-over-plan and plan-to-target analyses

- Year-over-year analysis of changes in resources (e.g., regular/temporary/Term/ETE Employee headcount, base OM&A, project OM&A, outage OM&A, capital expenditures, capital in-service additions, non-generation revenues and cost of goods sold, and provision expenditures).
    - Analysis should be provided in the form of a year-over-year continuity (roll) in a level of detail that is sufficient to fully explain the major drivers contributing to the change.
    - Work program changes should be separated from rate changes.
    - Analysis should include current year-end projections assumed in preparing year-over-year changes.
- Plan-over-plan comparison for 2025-2026 (i.e. relative to the 2025-2026 Budget).
- Plan-to-target reconciliations for applicable funding streams for 2025 to 2031.
- Plan-over-plan and plan-to-target reconciliations should reflect any budget transfers effective in the 2025 business planning year – i.e. prior year business plan and current targets should be restated to the current state of the organization for comparison purposes.
- Submitted through email to the Business Planning & Reporting email address, FPA@ontariopowergeneration.onmicrosoft.com, in the form of Excel spreadsheets and/or other documents.

2.1.1 Information Requirements for Specific Items

CONTACT: ARCHANA SRIJEYANATHAN

OM&A Expenses

- OM&A expenses reconciled to BU base, outage, and project OM&A targets per section 1.8.
    - If the submission exceeds targets, reconciliations should identify specific sources of variance from targets, and underlying drivers.
- Year-over-year and plan-over-plan analyses should identify material changes driven by outage profiles, non-standard projects, or non-recurring or infrequent events.
    - Significant drivers for non-labour resource changes should be separately identified.
    - Nuclear outage OM&A analysis should be provided including a summary of scope, outage duration and incremental OM&A costs.
- Monthly trending of annual years (i.e. 2026-2027) for BU OM&A expenses

Staffing

- Workforce demand headcount for regular and non-regular (e.g. temporary, augmented, EPSCA and Term/ETE Employees) positions should be reviewed and updated as necessary. The following principles apply:

    - Demand is to be planned by organization, resource skillset (minimum of occupation code), resource type, position location, and monthly headcount demand; and
    - Refer to workforce planning resources and/or BPC training manual for methodology on use of workforce planning templates and integration with business plan.
- Year-over-year and plan-over-plan analyses should identify material changes in key staffing plans to meet work program demands.

Capital

- Capital expenditures, including intangible assets and capital spares, as directed in section 2.7, and expenditures on minor fixed assets, together reconciled to capital expenditure targets outlined in section 1.4.
    - Reconciliations should identify reasons for variance and underlying drivers.
- Expenditures on capital spares should continue to be identified and input into the BPC system as a separate classification.
- Consistent with the capital project plan, BPC details and project lists, the following is to be provided:
    - Capitalized interest forecasts on a monthly basis for 2026-2027 and annually thereafter;
    - In-service addition forecasts input in the BPC system (major and constructed minor fixed assets):
        - For in-service additions >$50M, forecast month of in-service should apply instead of the half-year rule;
        - Instructions for inputting the in-service additions forecast in the BPC system are available in module 10 of the BPC manual, which is accessible on the BPC start page, under “Documents”; and
    - Quarterly asset retirements/write-offs forecasts for all years of the planning period.

Revenue and Gross Margin

- As outlined in section 2.2

Fuel Expense

- The following fuel expense details must be submitted to Generation & Revenue Planning as part of the inputs into the Energy Production and Revenue Plan, by the due date specified above:
    - Nuclear fuel;
    - GRC and related costs – both excluding and including forgone production due to surplus baseload generation conditions;
    - Gas/biomass fuel and building heating for thermal stations; and
    - Costs associated with carbon pricing program.

Provision Expenditures/Provisions

- Nuclear decommissioning and waste management provision expenditures, in line with guidance provided in section 2.1.5.
    - Expenditures should be provided for:
        - Decommissioning:
            - Pickering Safe State of Units 2 & 3;
            - Pickering Safe Storage of Units 1 & 4; and
            - Decommissioning Program.
        - Used Fuel Interim Storage and Disposal.
        - Low and Intermediate Level Waste Operations and Disposal.
    - Expenditures should be reconciled to targets provided by Nuclear Waste Management – Nuclear Liability Provision Management (see section 1.4.1).
    - If submissions exceed targets, reconciliations should identify specific sources of variance and underlying drivers.

- New provisions or provision updates expected during the planning period, where estimable.
- Drawdowns of existing provisions (including thermal decommissioning, environmental, etc.).

Nuclear Segregated Funds

- Submission of planning information for reimbursements from the nuclear segregated funds must be consistent with the planned drawdowns of the nuclear decommissioning and waste management provision, and will be coordinated by Nuclear Liability Provision Management.

Working Capital Items

- Monthly detail for the initial budget year and annual detail thereafter for the following:
  - Fuel inventory; and
  - Materials and supplies inventory.

2.1.2 Use of Responsibility Centres and Local Identifiers

CONTACTS: FARZAD SHOKREKHUDA

As in previous planning cycles, BU Controllers are required to review all existing RCs to ensure that planning/budgeting occurs only for RCs that have at least 20 employees **and** $5M in combined financial activity (OM&A, capital expenditures, revenues, and provision expenditures). Planning/budgeting can also occur for RCs that meet the following exceptions:

i) Direct reports of ELT members
ii) Facilities with energy supply agreements/commercial contracts
iii) Requirements exist to separate rate-regulated activities

All other exceptions require prior written justification from the local Controller to be forwarded to the Senior Manager or Director, Business Planning & Reporting. Exceptions approved in prior years should be reviewed to ensure that justifications remain valid for the current planning period.

As in previous years, BU Controllers are also requested to review the planning/budgeting “Local” identifiers for opportunities to reduce the level of detail. BU Controllers should ensure that the use of “Locals” is consistent within the respective BUs and is limited to instances where such identifiers are necessary for reporting and analysis of actual results.

2.1.3 Business Plan Materials for CEO Review

CONTACT: ARCHANA SRIJEYANATHAN

The CEO review of BU business plans is expected to take place in April and will be based on the BPC submissions. The review materials must be based on the standardized presentation requirements which will be emailed to business units by January 10, 2025. The template will contain the minimum requirements to be included in the presentation material. A reasonable amount of additional information may be included in appendices.

2.1.4 Cost Allocations

CONTACT: FARZAD SHOKREKHUDA

Business units are required to assign/allocate all submitted costs on the basis of OPG’s cost model and using OPG’s cost allocation methodology. This includes utilizing the appropriate client code under the cost model, a key element by which costs are directed to business segments at OPG. For RG specifically, this includes allocation between regulated and contracted plants, which must be applied consistently across RG Operations in accordance with the established methodologies.

Cost allocation templates are required to be input into BPC for all RCs that have planned OM&A Base with Project 00000 and Client 0000. The input template is available in BPC in the BUS folder.

BU Controllers and Analysts are encouraged to refer to the "BPC to BUS Validation Checklist" under the "MyBusiness Business Planning Reports" prior to confirming that dollars and allocations in BPC are complete. This will help with the accuracy of segment reporting and ensure a quicker turnaround of the business plan version of the BUS.

Proposed changes to allocation methodologies must be submitted to Business Planning & Reporting for review and approval prior to any change being applied.

The submission date for the above information is **February 21, 2025**.

2.1.5 Nuclear Provision Expenditures

CONTACT: GARRY LAM / WINNIE GUO / TINA MA

Planning for nuclear decommissioning and waste management provision expenditures requires the same rigour and change management process as OM&A and capital expenditures. Similar to OM&A, provision programs are classified as either Base or Project. The executive sponsors responsible for scope of work and annual expenditures, including VP, Nuclear Sustainability Services and VP, Nuclear Decommissioning Strategies, Nuclear SAFSTOR Division, will submit the respective consolidated budgets for approval to the Chief Operations Officer & Chief Nuclear Officer or Chief Project Officer, as applicable.

Only expenditures that are considered directly attributable to nuclear waste management and decommissioning activities and included in the provision should be planned as provision expenditures.

For staffing, 'directly attributable' is defined as follows:

- Base Programs (e.g. Used Fuel Storage and L&ILW Operations)
  - Normal part of employee's function.
  - For Support Services (e.g., HR, Finance, Real Estate & Services, Supply Chain, Law, Environment and others), employees who are fully dedicated in support of the Base Programs. Timesheet tracking of part-time support from multiple employees does not qualify.
- Projects (including SAFSTOR)
  - Employees working on nuclear waste management and decommissioning specific project activities and tracked within the time reporting system.

Business units are required to identify inter-business unit requirements for the SAFSTOR project, including staffing demand moving from Operations to the SAFSTOR project, through an SLA process. The SLAs should identify both expenditures and staffing requirements.

The Nuclear Liability Provision Management group will coordinate reviews/approvals and provide the approved consolidated funding and headcount levels to the Nuclear business planning team and Corporate Controllership for inclusion in the respective business plans by **February 14, 2025**.

Any changes to planning submissions for provision expenditures after the BU submission deadline, other than those explicitly contemplated by these instructions, must be reported to, and confirmed with Corporate Business Planning and Nuclear Liability Provision Management.

2.2 REVENUE AND GROSS MARGIN SUBMISSIONS

CONTACTS: DIRECTOR, GENERATION & REVENUE PLANNING / ARCHANA SRIJEYANATHAN

The accountabilities for revenue and gross margin submissions to Corporate Business Planning are outlined below (excluding self-sustaining subsidiaries, see section 2.3). Any expected sources of revenue not listed below should be identified to Corporate Business Planning and, as applicable, Generation & Revenue Planning, by the responsible Controller.

BU inputs to the Energy Production and Revenue Plan are to be provided to Generation & Revenue Planning by **February 7, 2025**. Some specific information requirements for the inputs may be required

earlier and will be communicated separately by Generation & Revenue Planning.

Cost inputs for determining applicable planned contract revenues must be submitted to Commercial Contracts by **February 14, 2025**. If there are changes to these inputs following the specified deadline, updated information must be provided as soon as possible.

Contract revenue plans, including inputs and assumptions, will be jointly reviewed by Commercial Contracts, RG Controllership, Corporate Business Planning, and Generation & Revenue Planning by **March 7, 2025.**

Unless otherwise specifically noted in the schedule in section 1.2, the below revenue and gross margin submissions are due to Finance – Business Planning on the general BU BPC submission date of **February 28, 2025.**

REVENUE SOURCE	ACCOUNTABILITY
Generation/Capacity Revenue (incl. new projects) • Regulated generation revenue • Contract and market-based revenue • Ancillary and other revenues • Trading margins (incl. OPGET)	Generation & Revenue Planning *(as part of Energy Production and Revenue Plan)* Corporate Business Planning will apply regulated rate assumptions to compute regulated generation revenues
Nuclear Non-Generation Revenue • Bruce Lease Rent and L&ILW Services	Nuclear Waste Management – Bruce Relationship
Nuclear Non-Generation Revenue* • Isotope Sales • Heavy Water Sales, Detritiation Services • Other	Nuclear
Real Estate Rentals*	Corporate Real Estate
RG Non-Generation Revenue*	RG
Training and Other Revenue*	Human Resources

** For marked items, the respective Controllership organization is responsible for inputting the planning submission into the BPC system, including monthly trending.*

2.3 NON-CONTROLLING INTEREST AND SELF-SUSTAINING SUBSIDIARIES

CONTACT: ARCHANA SRIJEYANATHAN

OPG is required to report a non-controlling interest in its financial results to reflect partners' equity ownership in certain generation development partnerships. For the planning period, Operations Controllership will identify the revenues and costs required to calculate income attributable to non-controlling interests. In addition, any cash distributions attributable to non-controlling interests must be identified.

OPG is required to consolidate the results of its controlled subsidiaries. Each of OPG's self-sustaining subsidiaries is required to submit a comprehensive business plan consisting of a detailed income statement, balance sheet, cash flow statement, generation plan, and staffing plan as well as a summary of key financial and operating assumptions. Underlying details should be provided for planned revenues, operating costs, capital expenditures and distributions. Planning submissions should separately identify requirements and assumptions for purchases of services from OPG and any other intercompany transactions. Submission of planning information will be coordinated by Business Planning, taking into account any restrictions on sharing of information consistent with any OEB licencing requirements.

The above information must be submitted to Corporate Business Planning by **February 21, 2025.**

2.4 OTHER CORPORATE-LEVEL INFORMATION SUBMISSIONS

CONTACTS: ARCHANA SRIJEYANATHAN / WEI SONG

The accountabilities for information submissions related to other cost and income items for this business planning cycle are outlined below. While Corporate Business Planning may initially receive some of these items from groups other than those identified below, it remains the responsibility of the accountable group to make the formal submissions in accordance with the business planning schedule. Key assumptions and dependencies should be identified in the submissions.

ITEM	ACCOUNTABILITY
2.4a Depreciation/Amortization – **March 7** ○ Based on current net book values of fixed/intangible assets, and station end-of-life dates/asset class lives expected to be in effect during the planning period	Accounting & Reporting – Central
2.4b Property Tax (separately showing amounts to be charged against nuclear and thermal decommissioning provisions and amounts to be capitalized) – **February 14**	Corporate Real Estate – Property Assessment and Taxation
2.4c Insurance – **February 21** ○ Summary of underlying Assumptions ○ Amounts to be charged against nuclear and thermal decommissioning provisions and amounts to be capitalized to be shown separately	Finance – Treasury *(costs submitted as part of Finance BPC submission)*
2.4d Employee incentive plans (centrally-held costs) – **March 7**	HR – Compensation
2.4e Pension Guarantee Fee (if applicable) – **March 7**	Finance – Treasury
2.4f Accretion on Nuclear Waste Obligations and Earnings on Nuclear Segregated Funds and accretion on non-nuclear decommissioning obligations – **March 7**	Nuclear Liability Provision Management
2.4g Pension and OPEB Costs update – **March 7**	Business Planning & Reporting – Actuarial
2.4h Deferral and Variance Accounts – **March 7**	Regulatory Finance
2.4i Asset Service Fees and Interest Expense	Corporate Business Planning *(for interest, reflecting inputs from Treasury and capitalized interest from BUs)*
2.4j Income Tax inputs	Income Tax

2.5 INSTRUCTIONS FOR USE OF THE BPC BUSINESS PLANNING SYSTEM

CONTACTS: KIRILL MELNIKOV / XIN WANG / WEI SONG / ARCHANA SRIJEYANATHAN

There will be several different versions of BPC utilized for the current business plan:

- **W01** contains preliminary data for the current planning cycle and updated for standard labour rates reflecting actual experience and payroll burden rates. All BUs will use BPC version W01 for planning.
- **W02** contains the preliminary planning data using previous standard labour rate and payroll burden rate assumptions. This version can be used to isolate the impact of the rate changes by comparing it to version W01.

Resource submissions and preliminary business plans are to be completed in version W01 by **February 21, 2025.**

Final trended information is required on a monthly basis for 2026-2027. All trending for 2026-2027 must be completed in W01 by **April 2025,** after which BUs will be locked out of the BPC system. At that point, the trending by the BUs will be considered final and, for the 2026 budget year, ready for upload to the reporting systems (subject to any adjustments arising out of the CEO reviews of BU business plans).

BU Controllers must ensure that the trended BPC input (BU OM&A, capital expenditures, provision expenditures, capital in-service additions, non-generation revenue as per section 2.2, and headcount) is complete, accurate and based on reasonable assumptions, and senior leadership review.

Additionally, the following input will be reflected in BPC:

- Nuclear Liability Provision Management will develop trending for accretion expense and earnings on nuclear segregated funds;
- In consultation with the responsible groups, Corporate Business Planning will develop trending for applicable centrally-held costs and review depreciation & amortization expense trending calculated in the BPC system based on BU capital in-service inputs;
- Trended BPC input for generation revenue will be provided by Generation & Revenue Planning and input by Revenue Accounting & Reporting incorporating regulated revenue assumptions from Corporate Business Planning as required; and
- Trended BPC input for deferral and variance accounts will be provided by Regulatory Finance.

2.6 BUDGETING FOR SERVICE PROVIDERS AND BUDGET TRANSFERS

CONTACT: JOE YIU

OPG's cost model is a company-wide set of business rules that are the foundation of financial planning, budgeting and cost reporting, and define how OPG accounts for resources. All business planning at OPG is to be conducted in accordance with OPG's cost model. Under the cost model, an organization at OPG plans for all the resources for which it is accountable, regardless of where the resources work or what they work on. This applies to labour, materials, purchased services, and other resources. The cost model also extends to projects, with project managers only budgeting for resources that are under their direct control.

The cost model requires identification, communication, agreement and documentation of inter-business unit service needs by Operating Business Units and Support Services as part of developing their respective business plans. Service recipients (in most cases, the Operating Business Units) are required to identify and estimate the annual resources that they expect to be supplied by other OPG organizations (in most cases, Support Services) for inter-business unit service needs. The identification and communication of this information must occur by **February 14**, with a signed agreement between the service providers and service recipients, a copy of which is to be provided to the respective Controllership organizations.

To help standardize and streamline planning processes, tools have been rolled out for the 2025-2031 Business Plan. This includes targets being entered into the BPC system in a separate folder called "BU Targets" within the Planning module and ability for planners to view the underlying audit trail and to execute submission-to-target comparison reports. Additionally, BUs are now required to use EBX Forms to record budget transfer and SLA data, which will be routed electronically for approval once submitted. EBX Forms will act as a database housing the budget transfer/SLA information, which will be reflected automatically in the BPC system once appropriate approvals are received. Only budget transfers affecting all planning years are currently housed in EBX Forms. Please contact local Finance support for further information.

Utilizing the EBX Forms tool for SLAs and budget will ensure that service providers' planning submissions adequately reflect the necessary resource levels (such as OM&A, capital including minor fixed assets, and provision expenditures) in accordance with the cost model. Service needs for which a signed agreement is not reached between BUs are expected to be brought forward to the CEO/CFO/ELT for resolution.

In addition, budget transfers between BUs affecting all planning years require formal sign-offs by **February 14** through the use of the EBX Forms tool. If an organizational change occurs after **February 14** or after the initial BPC submission date, Corporate Business Planning will evaluate on a case-by-case basis whether the planning system and BU business plans require updating.

Resources being planned by Support Services in support of the Darlington and Pickering Refurbishment projects require approval by the Chief Project Officer.

2.7 CAPITAL, OM&A AND PROVISION-FUNDED PROJECTS

CONTACT: TREVOR CARNEIRO

This section specifies the requirements for submission of the business plan capital, OM&A and provision-funded project portfolio listings and supporting BCSs or equivalent documentation.

2.7.1 Project Portfolio Review

BUs are required to identify all capital, OM&A and provision-funded projects having cash flows within the business planning period. The submitted projects must be prioritized considering risks and OPG's business objectives, as well as efficient alignment with BU strategies, equipment reliability, regulatory requirements, and Shareholder expectations.

In order to expedite portfolio review and prioritization, and to meet OEB information requirements, BUs are required to maintain documentation to justify projects listed in their portfolio that are ***not fully released*** and also meet the following criteria:

- Projects planned for release during the business plan period with a total project cost greater than or equal to $5M

For the purpose of these instructions, ***not fully released*** projects are projects that meet any of the following criteria:

- Projects with no previous release(s);
- Projects with previous release(s) other than a full execution phase release; and
- Previously released projects that are forecasting significant changes in scope or cost, and are planned or expected to have a superseding execution phase release.

These requirements include projects in support of non-generation business opportunities.

The documentation requirements can be met through any of the following forms:

- Nuclear: AIOT (Asset Investment Options Template) unless superseded by a Business Case Summary;
- CIO: Inclusion in Copperleaf database
- OPG-FORM-0076 Business Case Summary; and
- RG: Inclusion in Copperleaf database

Documents/rationale associated with unreleased projects (e.g. AIOTs, rationale contained within Copperleaf) are to be reviewed and approved by the appropriate project sponsor (e.g., Asset Manager, Engineering Director, etc.). The appropriate Finance manager also reviews and provides their concurrence, such as the local Controller (Nuclear, RG and Corporate). Finance's role in the review is intended to ensure that planned activities for projects not fully released are supported by an appropriate prioritization methodology and adequate documentation. The Finance manager must receive, review and concur with the Planning BCS or equivalent documentation to support the inclusion of projects within the plan by **February 14**.

For assistance with BCS preparation and project grouping/bundling, contact the local Business Planning group (if applicable) or local Controllership contact, or John Sim in Investment Management.

OPG Business Plan Targets

As referenced in section 1.4 of OPG's Business Planning Schedule and Assumptions (Attachment 2), Operating OM&A, Project OM&A and Sustaining Capital targets were provided in OPG's Business Planning system. Charts 1 and 2 below provide the associated Business Unit Operating OM&A[1] and Project OM&A targets (Chart 1) and Sustaining Capital Expenditures Targets (Chart 2).

Chart 1: Business Units Operating OM&A and Project OM&A Targets

OM&A Expenses	*Targets*					
(millions of dollars, years ending December 31)	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Operations Operating OM&A (Base & Outage OM&A)						
Nuclear base	650	400	401	428	444	739
Nuclear outage incremental	204	222	113	217	124	189
Renewable Generation operations [2]	[redacted]					
Enterprise Operations support	624	523	521	539	564	659
Enterprise Projects	12	9	9	10	10	10
Pickering cyclical maintenance [3]	25	168	161	169	170	107
Fuel Channel Life Extension and related costs	2	-	-	-	-	-
	[redacted]					
Support Services Operating OM&A (Base OM&A)						
Corporate Services	368	374	386	412	421	452
Commercial Operations and Regulatory Affairs	58	59	58	60	63	68
Corporate Affairs, Enterprise Strategy and Law	61	58	59	62	66	66
	487	491	503	534	550	586
Total Business Unit Operating OM&A	[redacted]					
Project OM&A						
Nuclear Projects	71	84	83	77	75	92
Renewable Generation Projects	[redacted]					
Support Services Projects	34	37	35	36	36	37
Total Project OM&A	[redacted]					
Total Operating and Project OM&A	[redacted]					

[1] Operating OM&A is defined as Business Unit Base and Outage OM&A (Excluding Subsidiaries).

[2] Adjusted to reflect the extension of Lennox GS beyond 2029 subsequent to the issuance of the Business Plan targets

[3] Adjusted to reflect the Release Quality Estimate for PRP that was approved by the OPG Board of Directors subsequent to the issuance of the Business Plan targets.

Chart 2: Sustaining Capital Expenditures Targets

Capital Expenditures (millions of dollars, years ending December 31)	Targets 2026	2027	2028	2029	2030	2031
Sustaining Capital						
Nuclear						
Nuclear Project Portfolio	477	649	494	513	547	492
Darlington SG Primary Moisture Separators	107	13	-	-	-	-
Darlington Turbine Rotor Replacements	112	129	202	325	302	292
TRF Major Component Replacement	35	56	19	26	31	31
Darlington U2 Turbine Control & Aux. System	28	66	4	-	-	-
Darlington U1 and 2 Generator Stator Rewind	6	12	88	23	73	4
Darlington Non-Routine SG Cleanings	15	16	15	15	-	-
Pickering Water Treatment Plant	-	-	-	-	98	-
Nuclear Refurbishment New Fuel [4]	-	-	-	-	24	25
DNNP Capitalized Fuel [5]	-	-	-	-	78	29
	780	941	822	902	1,153	873
Regulated Hydroelectric						
Regulated Hydroelectric Project Portfolio	265	262	300	312	328	312
Regulated Hydroelectric Refurbishments	325	437	546	534	554	499
Regulated Hydroelectric Redevelopments	342	145	28	5	8	8
Abitibi Canyon Concrete and Sluiceway Rehab.	6	11	35	100	137	161
Sir Adam Beck Power Canal Infrastructure	10	72	74	121	2	2
	948	927	983	1,072	1,029	982
Contracted Hydroelectric and Thermal						
Smoky Falls Dam Safety	[redacted]					
Other Contracted [6]						
Support Services						
Corporate Technology Services Project Portfolio	100	126	127	132	131	136
DNNP Operational Readiness Tech. Projects [5]	36	28	23	20	16	19
Real Estate Project Portfolio	24	26	32	35	35	41
	160	180	182	187	182	196
Total Sustaining Capital Expenditures	[redacted]					

[4] Adjusted to reflect the Release Quality Estimate for PRP that was approved by the OPG Board of Directors subsequent to the issuance of the Business Plan targets.
[5] Adjusted to reflect a revised forecast for the impact associated with the Release Quality Estimate for DNNP that was approved by the OPG Board of Directors subsequent to the issuance of the Business Plan targets.
[6] Adjusted to reflect the extension of Lennox GS beyond 2029 subsequent to the issuance of the Business Plan targets

RATING AGENCY REPORTS

1.0 PURPOSE

This evidence provides the rating agencies' financial assessments of OPG.

2.0 CREDIT RATING OVERVIEW

OPG is currently rated by three credit rating agencies – S&P Global Ratings ("S&P"), DBRS Morningstar ("DBRS") and Moody's Investors Service ("Moody's"). As of the filing date of this Application, OPG has a long-term credit rating of 'BBB+' by S&P, 'A (low)' by DBRS and 'A3' by Moody's, and a short-term Canadian Scale Commercial Paper debt rating of 'A-1 (low)' by S&P and 'R-1 (low)' by DBRS. There have been no changes to OPG's credit ratings since the EB-2020-0290 payment amounts application.

Copies of the rating agency reports for each of the historical years and bridge year from DBRS, Moody's and S&P are provided in Attachments 1-13.[1]

[1] Moody's did not issue a report in 2021 and no reports have been issued by S&P in 2025.

LIST OF ATTACHMENTS

Attachment 1:	DBRS Morningstar, April 21, 2021
Attachment 2:	DBRS Morningstar, April 25, 2022
Attachment 3:	DBRS Morningstar, May 5, 2023
Attachment 4:	DBRS Morningstar, April 30, 2024
Attachment 5:	DBRS Morningstar, April 21, 2025
Attachment 6:	Moody's Investor Service, April 1, 2022
Attachment 7:	Moody's Investor Service, June 12, 2023
Attachment 8:	Moody's Investor Service, June 24, 2024
Attachment 9:	Moody's Investor Service, June 30, 2025
Attachment 10:	S&P Global Ratings, August 13, 2021
Attachment 11:	S&P Global Ratings, August 3, 2022
Attachment 12:	S&P Global Ratings, August 8, 2023
Attachment 13:	S&P Global Ratings, August 14, 2024

MORNINGSTAR | DBRS

Rating Report
Ontario Power Generation Inc.

DBRS Morningstar
April 21, 2021

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Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A (low)	Confirmed	Stable
Unsecured Debt	A (low)	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

DBRS Limited (DBRS Morningstar) confirmed the Issuer Rating and Unsecured Debt rating of Ontario Power Generation Inc. (OPG or the Company) at A (low) and the Commercial Paper (CP) rating at R-1 (low). All trends are Stable. The ratings of OPG are primarily based on the Company's regulated electricity generation business under the Ontario Energy Board (OEB), which provides a stable stream of cash flows.

In November 2020, the Province amended Ontario Regulation (O. Reg.) 53/05 to freeze OPG's regulated hydroelectric payment amounts for the next regulatory period of 2022–26 at the 2021 level. DBRS Morningstar does not expect this change to have a material impact on the Company although earnings may be modestly pressured as efficiencies must be found to offset inflationary cost increases. In December 2020, OPG filed its application with the OEB for 2022–26 payment amounts related to its regulated nuclear business. In its application, the Company largely applied for the continuation of its current Custom Incentive Rate-setting (IR) framework for its nuclear operations. If approved as requested, the decision would provide certainty for OPG's capital expenditures (capex) program for the remainder of the Darlington Refurbishment project (the Darlington Refurbishment; total capex of $12.8 billion).

In June 2020, OPG returned the first unit of the Darlington Nuclear Generating Station (GS) to service. DBRS Morningstar notes that the refurbishment of the first unit was completed on budget and largely on schedule. In September 2020, the Company began refurbishment of the second unit. While the overall project remains on schedule and on budget, OPG has noted that uncertainty about the Coronavirus Disease (COVID-19) pandemic could lead to delays and cost increases. DBRS Morningstar will continue to monitor the Darlington Refurbishment and any changes in scheduling and budget. Should there be significant cost overruns with the Darlington Refurbishment that result in stranded costs, a negative rating action may occur.

Despite the coronavirus pandemic, OPG was able to achieve its operational and financial results in 2020. The Company's earnings benefitted from higher regulated rates for nuclear operations and increased contributions from nonregulated operations. In April 2020, OPG completed a $2.8 billion acquisition of a portfolio of natural gas-fired generation assets in Ontario totalling 1,864 megawatts (MW). DBRS Morningstar noted that the overall impact of this acquisition was minimal on the Company's credit profile as regulated operations and assets under regulatory-style contracts will continue to contribute more than 80% of EBITDA. Although the acquisition was fully debt funded, OPG's key credit metrics remain in line with the A (low) ratings. DBRS Morningstar notes that the Company has indicated that growth in its nonregulated business will be at a more moderate pace following these acquisitions, with most planned capex for its regulated operations. However, should OPG pursue acquisitions that result in a significant shift in the EBITDA mix between regulated and nonregulated operations or lead to credit metrics deteriorating to a level no longer supportive of the current rating category, DBRS Morningstar may take negative rating action. Conversely, a positive rating action is unlikely in the medium term, given the ongoing capex program, including that for the Darlington Refurbishment.

Financial Information

	For the year ended December 31				
	2020	**2019**	**2018**	**2017**	**2016**
Cash flow/Total debt (%)[1, 2]	39.3	41.7	45.0	40.0	40.6
Total debt in capital structure (%)[1, 2, 3]	33.8	28.6	26.9	26.2	34.3
EBIT gross interest coverage (times)[1, 2, 4]	3.66	0.86	1.00	(0.24)	(0.14)
(Cash flow – n.w.f.)/Total debt (%)[1, 2, 5]	36.3	39.0	39.3	33.7	32.9

1 Including operating leases.
2 Excludes nonrecourse debt.
3 Adjusted for Accumulated Other Comprehensive Income.
4 Excluding earnings from nuclear fixed asset removal and nuclear waste management funds.
5 Includes nuclear waste funding (n.w.f.) payments as they are not discretionary.

Issuer Description

OPG is an electricity generation company with a diverse portfolio of over 18,000 MW of in-service generating capacity. The Company is wholly owned by the Province of Ontario.

Rating Considerations

Strengths

1. Reasonable regulatory framework that provides stable cash flow

The reasonable regulatory framework has allowed the Company to recover prudently incurred costs and provided stable cash flows. DBRS Morningstar notes, however, that there have been disallowances by the OEB in the past on labour compensation costs related to OPG's nuclear operations. DBRS Morningstar also notes that, under an IR framework, OPG's profitability could come under further pressure because of the need to meet efficiency and productivity benchmarks.

2. Support of shareholder (the Province)

The Province indirectly provides OPG with some of its long-term funding requirements through the Ontario Electricity Financial Corporation (OEFC; rated AA (low) with a Stable trend by DBRS

Morningstar), a government financing arm for provincial power companies. DBRS Morningstar believes that the Province will continue to support its investment because OPG is a creation of the Province and is integral to fulfilling Ontario's energy needs. OPG's importance in Ontario is also demonstrated by the fact that it is the primary electricity generator in the province, accounting for approximately 54% of electricity produced in 2020.

DBRS Morningstar notes that OPG's debt is not directly guaranteed by the Province. As at December 31, 2020, OPG had approximately $2.9 billion of notes payable to the OEFC, comprising 28% of the Company's outstanding debt. While this financial support does not, in itself, result in any uplift to the Company's ratings, the ratings do incorporate DBRS Morningstar's belief that the Province will, in exceptional circumstances, provide support to OPG.

3. Limited nuclear waste management liabilities

As a result of the Ontario Nuclear Funds Agreement with the Province, OPG's exposure to the costs to dispose of the initial 2.23 million used fuel bundles produced has been capped at $5.94 billion (in 1999 dollar terms). The used fuel obligation is funded by the used fuel fund, which was fully funded as at December 31, 2020. The Province provides a guarantee for any shortfall between the value of the nuclear fund and the Canadian Nuclear Safety Commission consolidated financial guarantee requirement.

Challenges

1. Significant capex program

OPG has a significant capex program underway (approximately $2.5 billion planned for 2021). The Company also faces significant execution risk as well as the potential for cost overruns associated with the Darlington Refurbishment because of the project's complexity and scale. While DBRS Morningstar is encouraged because the first unit of the Darlington Refurbishment was completed on budget and on schedule, there are still three more units to be refurbished. DBRS Morningstar expects that OPG will not undertake any major capex without having financing and a cost-recovery mechanism in place, thus minimizing financial risks.

2. Nuclear generation risks

Nuclear generation (approximately 53% of OPG's production in 2020) faces higher operating risks than other types of power generation because of its complex technology. The financial implications of forced outages, especially with older units (e.g., the Pickering Nuclear GS), are greater, given the high fixed-cost nature of these plants and because lost revenues resulting from outages are not recoverable through rates.

3. High cost base

OPG's high cost base has resulted in several disallowances by the OEB. For the most recent 2017–21 rates decision, the OEB disallowed recovery of $100 million in the operations, maintenance, and administration (OM&A) budget annually. DBRS Morningstar believes that OPG's inability to fully recover compensation costs in future regulated prices could have a negative impact on earnings and affect the

Company's ability to achieve its approved return on equity (ROE). DBRS Morningstar notes that OPG has been combatting this issue through its cost-reduction and efficiency-improvement initiative, which has saved $1.0 billion through a reduction in headcount of over 2,800 since 2011.

4. Political intervention

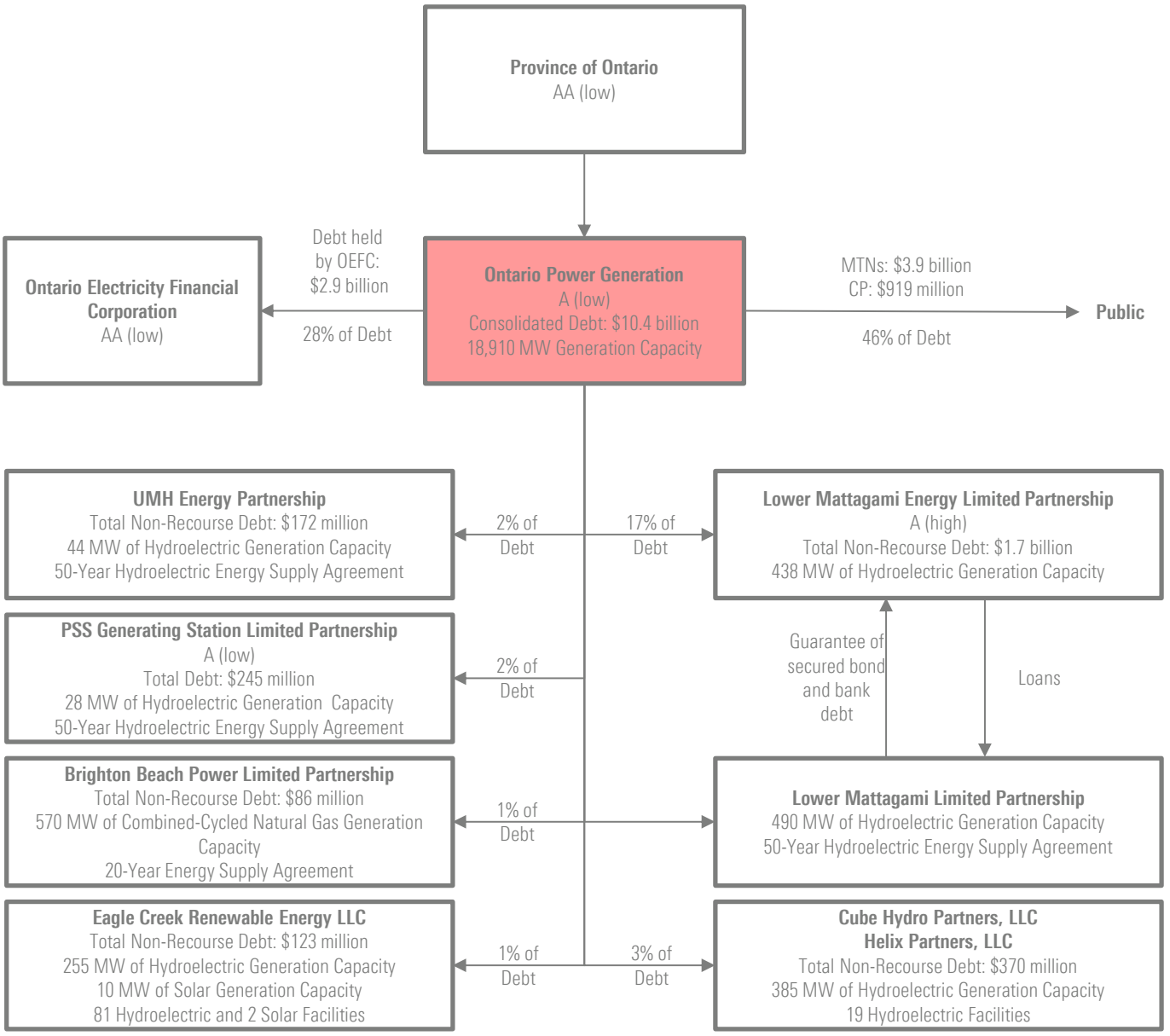
OPG is subject to political intervention, largely because of its ownership by the Province and changes in government mandates and policies. DBRS Morningstar notes that, though the Province has committed to having the Company run more autonomously, the risk of further government intervention still exists. In November 2020, the Province amended legislation to freeze OPG's hydroelectric rates at the 2021 level for the next regulatory period of 2022–26. DBRS Morningstar expects the Company's earnings to be modestly pressured as OPG will have to find efficiencies to offset inflationary cost increases.

5. Increased exposure to nonregulated operations

OPG has in recent years acquired multiple nonregulated generation assets, including gas-fired plants in Ontario and two renewable facility operators in the United States (Eagle Creek Renewable Energy LLC (Eagle Creek) and Cube Hydro). The Company also owns nonregulated natural gas, oil, solar, and biomass generation assets in the province. While the Ontario assets are largely under long-term contracts with strong investment-grade counterparties (such as the Independent Electricity System Operator (IESO; rated A (high) with a Stable trend by DBRS Morningstar)) and contribute relatively stable earnings and cash flow, DBRS Morningstar does view nonregulated assets as generally having higher business risks than the incumbent regulated operations because there is less cost recovery certainty and potentially more volatile cash flow. DBRS Morningstar notes that, following the acquisition of three Ontario natural gas-fired assets in 2020, earnings contributed by nonregulated operations will remain moderate at below 20% and are expected to decrease as most future capex is for regulated operations. DBRS Morningstar also considers assets under regulatory-styled contracts (such as Lower Mattagami Energy Limited Partnership (LMELP; rated A (high) with a Stable trend by DBRS Morningstar), PSS Generating Station Limited Partnership (PSS; rated A (low) with a Stable trend by DBRS Morningstar) and UMH Energy Partnership (UMH; not rated by DBRS Morningstar)) to have similar credit risks as regulated operations because those contracts mimic the current regulatory construct under the OEB.

Organizational Chart

Simplified Organizational Chart

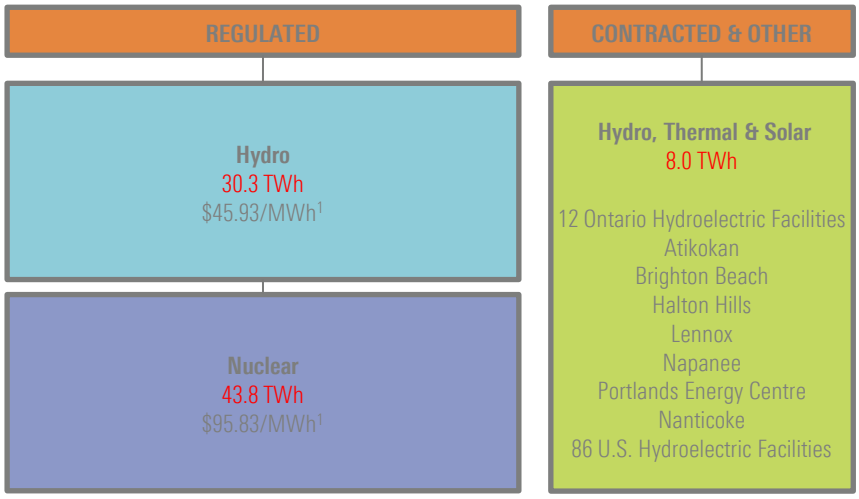


As of December 31, 2020.

Source: OPG.

- As at December 31, 2020, debt at the OPG corporate level consists of $2.9 billion held by the OEFC, $3.9 billion of medium term notes (MTNs), and $919 million of CP outstanding.
  - Debt at UMH, LMELP, Brighton Beach GS, Eagle Creek, and Cube Hydro are secured by the assets at each corresponding subsidiary and are nonrecourse to OPG.
  - Debt at PSS GS is recourse to OPG until the recourse release date.

Price Structure



1 Rates as of January 1, 2021.
For the year ended December 31, 2020.

Source: OPG.

- OPG sells electricity to consumers through the IESO.
- Regulated facilities sell at rates set by the OEB, which could include rate riders used for the recovery of nuclear deferral and hydroelectric variance account balances.
- The Contracted and Other Portfolio includes (1) assets in Ontario that sell electricity at prices set through Energy Supply Agreements (ESA) or other long-term contracts with the IESO and (2) Eagle Creek, which holds interest in 100 hydroelectric GS and two solar facilities throughout the United States.
  - The Eagle Creek and Cube Hydro facilities either sell into the merchant market or operate under long-term energy or capacity supply contracts.

Major Projects

Project	Estimated Cost (CAD millions)	Spent as of Dec. 31, 2020 (CAD millions)	In-Service Target Date
Darlington Refurbishment	12,800	7,446	2026[1]
Little Long Dam Safety Project	650	102	2023
Sir Adam Beck I GS Units G1 and G2 Replacement	128	54	2022
Calabogie Hydroelectric GS	137	30	2022
Ranney Falls Hydroelectric GS	77	71	2021

1 Four units with staged in-service. Last unit scheduled to be completed by 2026.

- **Darlington Refurbishment**: The Darlington Refurbishment will extend the operating life of the Darlington Nuclear GS by approximately 30 years. The execution of the refurbishment of the first unit began in October 2016 and the last unit is scheduled to be completed by 2026. Construction on the first unit was completed in March 2020 and returned in service in June 2020. Refurbishment on the second unit

began in September 2020 after a short delay related to the coronavirus pandemic. The project remains on schedule and on budget.

- **Little Long Dam Safety Project**: This project is intended to make reliability and operational improvements and increase the discharge capacity at the Little Long Dam. The Little Long Dam supports hydroelectric GSs on the Lower Mattagami River.
- **Sir Adam Beck 1 GS Units G1 and G2 Replacement**: This project is intended to replace two older generators at the Sir Adam Beck 1 GS, adding 125 MW of incremental capacity.
- **Calabogie Hydroelectric GS**: This project is intended to redevelop the Calabogie GS by replacing the powerhouse to 11 MW from 5 MW.
- **Ranney Falls Hydroelectric GS**: This project will replace an existing generation unit at Ranney Falls with a 10 MW single-unit powerhouse. While construction was completed in 2019, the unit was damaged during commissioning. The vendor will disassemble, repair, and reassemble the unit at their own cost.
- In April 2020, OPG completed its acquisition of the Napanee and Halton Hills GSs and the remaining 50% interest in the Portlands Energy Centre from affiliates of TC Energy Corporation (rated Pfd-2 (low) with a Stable trend by DBRS Morningstar) for approximately $2.8 billion. These assets are combined-cycle natural gas-fired plants located in Ontario and added 1,864 MW of generating capacity to the Company. DBRS Morningstar notes that, although these assets have a higher business risk than OPG's incumbent regulated operations, earnings and cash flows from these assets are expected to be relatively stable as they are supported by long-term contracts with an investment-grade counterparty (IESO).

Regulation

- OPG benefits from a reasonable regulated environment. As at December 31, 2020, approximately 64% of its installed in-service capacity is regulated.
- OPG, regulated by the OEB under the Electricity Restructuring Act, 2004 (Ontario), is allowed to receive regulated prices for all electricity generated from its nuclear facilities (5,728 MW) as well as most of its hydroelectric power facilities (6,420 MW).
- In December 2017, the OEB issued its decision on OPG's application for rates effective January 1, 2017.
    - The OEB approved rates to be effective June 1, 2017, rather than the applied-for effective date of January 1, 2017.
    - Capital structure will remain at 55% debt (the Company had requested a change to 51% debt) and an allowed ROE of 8.78%. The ROE will not be updated throughout the five-year term.
    - For hydroelectric facilities, the Price Cap IR methodology is used. Under Price Cap IR, rates for the hydroelectric facilities are subject to a formula price cap that allows for an annual increase in the payment amount based on inflation less productivity and a utility-specific stretch factor, which can be reset annually (productivity factor of 0%, stretch factor of 0.3%).
    - Under Price Cap IR, OPG could file an Incremental Capital Module (ICM) application to potentially recover any material and necessary prudently spent incremental capex during the IR period of five years. Additionally, the Company could ask to initiate a regulatory review of its application if actual ROE falls 300 basis points below the approved ROE.
    - For nuclear facilities, OPG requested the use of a Custom IR methodology and a rate-smoothing deferral account. Under its Custom IR methodology, nuclear revenue requirements were determined by a five-year forecast cost-of-service (COS) approach, but with a stretch factor of 0.6%

applied to the Company's OM&A expenditures. The reduction in OM&A costs as a result of the stretch factor will accumulate for the five-year period. The rate-smoothing deferral account (as required under O. Reg. 53/05) will stabilize year-to-year changes to weighted-average payment amounts as the Darlington Refurbishment continues. OPG will defer a portion of its approved nuclear revenue requirements into the rate-smoothing deferral account and will be allowed to recover the deferred amount, and any amount to be deferred from 2022 to 2026, over a 10-year period once the Darlington Refurbishment has been completed.
    - The OEB reduced the nuclear OM&A budget by $100 million per year for a total of $500 million over five years. Additionally, the OEB did not approve a mid-term review (prior to July 1, 2019) to update the nuclear production forecast.
    - The OEB approved the inclusion of $5.5 billion to the rate base over the five-year period of the Custom IR for the Darlington Refurbishment. Any cost overruns will be subject to a prudence review before being added to the rate base.
    - The OEB also approved the recovery of balances as at December 31, 2015, in OPG's deferral and variance accounts.
- In December 2019, the OEB approved the Company's Application for 2020 Hydroelectric Payment Amount Adjustment to be effective January 1, 2020.
    - The OEB approved a 1.5% base rate increase based on an inflation factor of 1.8%.
- In December 2020, the OEB approved the Company's Application for 2021 Hydroelectric Payment Amount Adjustment to be effective January 1, 2021.
    - The OEB approved a 1.7% base rate increase based on an inflation factor of 2.0%.
- In November 2020, the Province amended O. Reg. 53/05 to freeze hydroelectric rates for OPG at the 2021 level for the next regulatory period of 2022–26.
    - Rates for nuclear facilities will not be frozen and will continue to be set by the OEB.
    - DBRS Morningstar notes the hydroelectric rate freeze may modestly pressure the Company's earnings as OPG will have to find efficiencies in its regulated hydroelectric operations to offset inflationary cost increases.
- In December 2020, OPG filed its application with the OEB for rates effective January 1, 2022.
    - As per O. Reg. 53/05, OPG has requested hydroelectric base payment amounts to remain at the 2021 level.
    - The Company requested a change to its capital structure to 50% debt (currently 55% debt) and for the allowed ROE to be determined by the 2022 cost of capital parameters.
    - For nuclear facilities, OPG has requested the continuation of the current Custom IR methodology, but with the stretch factor reduced to 0.45% for 2023–25, and 0.3% for 2026.
    - The Company has requested the continuation of the rate-smoothing deferral account and has proposed one additional deferral account related to the closing of the Pickering Nuclear GS.
    - OPG requested the following for its nuclear facilities:

Effective Date	January 1, 2022	January 1, 2023	January 1, 2024	January 1, 2025	January 1, 2026
Revenue requirement, net of stretch factor (CAD millions)	3,611.4	3,540.8	3,644.2	3,324.5	2,550.9
Rate base (CAD millions)	8,720.4	8,788.7	11,260.7	12,468.5	13,312.0
Payment amount ($ per MWh)	101.51	105.13	104.42	106.70	120.67

Assessment of Regulatory Framework

Criteria	Score	Analysis
1. Deemed Equity	Excellent	The OEB allows OPG to have a deemed equity of 45%.
	Good	
	Satisfactory	
	Below Average	
	Poor	
2. Allowed ROE	Excellent	OPG has an allowed ROE of 8.78% for 2017–21, which is in line with the other regulated utilities in Ontario. Any difference in ROE between the Company and other regulated utilities in the province is mainly because of the timing of the regulatory filings and the interest environment prevalent at that time.
	Good	
	Satisfactory	
	Below Average	
	Poor	
3. Energy Cost Recovery	Excellent	N/A; energy costs are recovered through rates for OPG.
	Good	
	Satisfactory	
	Below Average	
	Poor	
4. Capital and Operating Cost Recovery	Excellent	Under Price-Cap IR for the hydroelectric facilities, major capital costs are pre-approved at the time of the COS application. If incremental costs are significant and prudent, OPG can file under ICM to request recovery of the costs. Under Custom IR for the nuclear facilities, the capex program for OPG is pre-approved for a five-year period by the OEB and recovered through base rates. Future test years are utilized for both hydroelectric and nuclear rates applications. Some volume risk exists but this is partly mitigated by (a) historically stable throughputs for the hydroelectric facilities, (b) use of deferral accounts for volumetric differences, and (c) for nuclear facilities, rates are based on forecasts which include scheduled outages. However, lost revenues resulting from forced outages are not recoverable through rates.
	Good	
	Satisfactory	
	Below Average	
	Poor	
5. COS versus IRM	Excellent	The hydroelectric facilities are regulated under the Price Cap IR framework, with four years between the COS rebasing years. The nuclear facilities operate under Custom IR, which is a hybrid of COS and the IR framework, for a five-year term. DBRS Morningstar considers the inflation, productivity (0%), and stretch (0.3% for hydroelectric and 0.6% for nuclear) factors as reasonable.
	Good	
	Satisfactory	
	Below Average	
	Poor	
6. Political Interference	Excellent	The Government of Ontario plays a significant role in the electricity sector in Ontario, given that most of the utilities are government owned (OPG is owned by the Province). Furthermore, stakeholders, such as the IESO, are also government owned. As a result, the government has direct and indirect influence on Ontario's electricity industry.
	Good	
	Satisfactory	
	Below Average	
	Poor	
7. Stranded Cost Recovery	Excellent	Regulated utilities in Ontario have a limited history of stranded costs. Most prudently incurred or budgeted capex is approved by the OEB. While OPG has seen some write-downs, these have been because the OEB had deemed the costs overruns to have been imprudent.
	Good	
	Satisfactory	
	Below Average	
	Poor	
8. Rate Freeze	Excellent	DBRS Morningstar notes that, in November 2020, the Province amended O. Reg. 53/05 to freeze hydroelectric rates for the Company at the 2021 level for the next regulatory period from 2022 to 2026. Rates for nuclear facilities will not be frozen and will continue to be set by the OEB. DBRS Morningstar notes that the hydroelectric rate freeze may modestly pressure OPG's earnings as the Company will have to find efficiencies to offset inflation.
	Good	
	Satisfactory	
	Below Average	
	Poor	

Earnings and Outlook

	For the year ended December 31				
(CAD millions where applicable)	**2020**	**2019**	**2018**	**2017**	**2016**
Revenues	7,240	6,022	5,535	5,158	5,653
EBITDA[1]	2,459	1,496	1,017	642	1,207
EBIT[1]	1,137	423	233	(37)	(50)
Gross interest expense	416	345	301	296	298
Earning before taxes[1]	835	439	225	(92)	(116)
Net income before nonrecurring items[1]	679	469	274	(14)	(106)
Reported net income	1,361	1,126	1,195	860	436
Return on equity (%)	4.6	3.4	2.2	-0.1	-1.0
Hydroelectric rate base	N/A	N/A	N/A	N/A	7,447
Nuclear rate base	7,347	3,374	3,446	3,628	3,573
Approved regulated ROE (%)	8.78	8.78	8.78	8.78	9.19
Achieved regulated ROE (%)	N/A	15.72	10.69	5.88	3.80

1 Excluding earnings from nuclear fixed asset removal and nuclear waste management funds.

2020 Summary

- EBITDA and EBIT increased significantly in 2020 for OPG because of higher regulated rates for nuclear facilities, and higher contracted revenues following the acquisition of natural gas assets in April 2020.
  - This was partly offset by higher depreciation from the growing rate base and regulatory commitments in support for the continued operation of the Pickering Nuclear GS.
- Net income from nonrecurring items increased as well, tracking the higher EBIT.
  - OPG reported a corporate ROE of 9.0% for 2020, in line with the approved regulatory ROE of 8.78%.

2021 Outlook

- OPG has forecast net income in 2021 to decrease compared with 2020.
  - This decrease is largely because Unit 3 of the Darlington Nuclear GS will be out for refurbishment for the full year, and planned cyclical maintenance of Units 1 and 4 during the year, reducing electricity production as well as a corresponding increase in expenses.
  - Higher depreciation on the growing rate base will also affect earnings.
  - The Company expects these impacts will be partly mitigated by higher generation from Pickering Nuclear GS, a full year's operation of Unit 2 of the Darlington Nuclear GS following the completion of its refurbishment in June 2020, and higher contributions from the nonregulated portfolio.
- DBRS Morningstar does not expect the ongoing pandemic to have a material impact on OPG's earnings as even with potentially lower electricity demand in the province, volume risk for hydroelectric generation is limited through deferral accounts which allow the Company to recover any foregone production because of surplus baseload generation conditions.
- Earnings volatility going forward will come from (1) forecast risk as part of the IR process and (2) macro factors such as weather, unexpected outages, and Ontario’s economic conditions.

Financial Profile

	For the year ended December 31				
(CAD millions where applicable)	**2020**	**2019**	**2018**	**2017**	**2016**
Net income before nonrecurring items[4]	679	469	274	(14)	(106)
Depreciation & amortization	1,322	1,073	784	679	1,257
Deferred income taxes and other	1,315	1,026	1,147	1,070	1,081
Cash flow (bef. working cap. changes)	**3,316**	**2,568**	**2,205**	**1,735**	**2,232**
Nuclear waste funding	(439)	(336)	(307)	(313)	(425)
Dividends paid	0	0	(283)	0	0
Capital expenditures	(1,765)	(2,058)	(1,826)	(1,853)	(1,816)
Free cash flow (bef. working cap. changes)	**1,112**	**174**	**(211)**	**(431)**	**(9)**
Changes in noncash working cap. items	103	99	(160)	80	180
Change in regulatory assets/liabilities	(156)	275	(51)	(558)	(170)
Net free cash flow	**1,059**	**548**	**(422)**	**(909)**	**1**
Long-term investments	(2,814)	(1,232)	(358)	0	(213)
Proceeds on asset sales	0	11	289	554	110
Acquisition of Fair Hydro Trust receivables	0	0	(609)	(1,179)	0
Change in Fair Hydro Trust debt	0	0	306	601	0
Net equity change	0	0	268	519	0
Net debt change	1,993	866	622	458	(162)
Other	(11)	(8)	(17)	4	(14)
Change in cash	**227**	**185**	**79**	**48**	**(278)**
Total debt	10,429	8,445	7,878	6,579	5,522
Total debt[2]	7,928	5,729	4,730	4,053	5,340
Cash flow/Total debt (%)[1, 2]	39.3	41.7	45.0	40.0	40.6
Total debt in capital structure (%)[1, 2, 3]	33.8	28.6	26.9	26.2	34.3
EBIT gross interest coverage (times)[1, 2, 4]	3.66	0.86	1.00	(0.24)	(0.14)
(Cash flow - n.w.f.)/Total debt (%)[1, 2, 5]	36.3	39.0	39.3	33.7	32.9

1 Including operating leases.
2 Excludes nonrecourse debt.
3 Adjusted for Accumulated Other Comprehensive Income.
4 Excluding earnings from nuclear fixed asset removal and nuclear waste management funds.
5 Includes nuclear waste funding (n.w.f.) payments as they are not discretionary.

2020 Summary

- OPG's key credit metrics exclude nonrecourse debt from UMH (recourse released in 2014), LMELP (recourse released in 2017), Fair Hydro Trust (derecognized in 2019), Eagle Creek, Cube Hydro, and Brighton Beach GS.
  - The cash flow-to-debt and debt-to-capital metrics both weakened modestly because of debt issued to fund the acquisition of the natural gas assets in Ontario. These two ratios remained strong though.
  - The EBIT-to-interest coverage ratio improved significantly because of the stronger EBIT for the year.
- Cash flow from operations increased, tracking the higher net income.

- Capex decreased to $1.7 billion following the completion of Unit 2 of the Darlington Refurbishment in June 2020 and with refurbishment on Unit 3 delayed slightly until September 2020 because of the pandemic.
- Long-term investments of $2.8 billion represent the acquisition of the Napanee GS, Halton Hills GS, and the remaining 50% interest in the Portlands Energy Centre from TC Energy completed in April 2020.
- OPG issued $400 million of debt to the OEFC and $1.6 billion of Senior Notes under the MTN program.
    - Proceeds were used to repay $660 million of OEFC debt and to finance the natural gas portfolio acquisition.

2021 Outlook

- Key credit metrics are expected to weaken in 2021 but remain in line with the current ratings.
    - OPG's adjusted cash flow-to-debt ratio is expected to decrease to around 25% from the historical average of around 40% largely because of weaker cash flows expected for the year and the increase in debt in 2020 to fund the natural gas portfolio acquisition. DBRS Morningstar notes that the Company's cash flow-to-debt ratio had been strong for the rating and will still be in line with the current ratings.
    - Debt-to-capital for OPG is expected to remain steady while the EBIT-interest coverage ratio will return to levels more similar to 2019 results.
- Cash flow from operations is expected to decrease to 2019 levels because of the lower earnings for the year.
- OPG has forecast capex of $2.5 billion for 2021 largely because of a full year's work on the Unit 3 Darlington Refurbishment and work on the Little Long Dam Safety Project.
- In February 2021, OPG issued $500 million of debt, with the proceeds used to repay existing indebtedness, working capital requirements, and general corporate purposes.

Long-term Debt and Credit Facilities

Long-Term Debt

(CAD millions)	Maturity	Dec. 31, 2020	Dec. 31, 2019
Notes payable to the OEFC	2021–48	2,875	3,135
Medium Term Note Program	2025–50	3,850	2,250
UMH Energy Partnership[1]	2041	172	175
PSS Generating Station Limited Partnership[2]	2067	245	245
Lower Mattagami Energy Limited Partnership[1]	2021–52	1,595	1,595
Brighton Beach Power Limited Partnership[1]	2021–24	86	116
Eagle Creek[1]	2025–30	123	307
Cube Hydro[1]	2025–35	370	385
Other		25	25
Subtotal		**9,341**	**8,233**
Less: Fair value discount		24	20
Less: Bond issuance fees		(33)	(27)
Less: Current portion		(439)	(693)
Total long-term debt		**8,893**	**7,533**

1 Nonrecourse to OPG as debt is secured by assets of the associated project.
2 Secured by assets of the project; recourse to OPG until the recourse release date.

- In March 2020, OPG issued $400 million of Senior Notes to the OEFC with a maturity date of 2024 at an effective interest rate of 1.75%.
  - The Company also repaid $660 million of Senior Notes owed to the OEFC during 2020.
- In April 2020, the Company issued $1.2 billion of Senior Notes with $400 million maturing in 2025 at a coupon rate of 2.89% and $800 million maturing in 2030 at a coupon rate of 3.22%. In October 2020, the Company issued an additional $400 million of Senior Notes maturing in 2026 with a coupon rate of 1.17%.
  - In February 2021, the Company issued $500 million of Senior Notes maturing in 2051 at a coupon rate of 2.95%.
- The amortizing UMH notes were issued in 2009 with a maturity date of 2041 and an effective interest rate of 7.86%. The notes are secured by the assets of the Upper Mattagami and Hound Chute project and are nonrecourse to OPG.
- The amortizing PSS GS notes were issued in 2015 with a maturity date of 2067 and an effective interest rate of 4.90%. The notes are secured by the assets of PSS GS and are recourse to OPG until the recourse release date (expected in 2021).
- The LMELP notes are secured by the assets of the project and are nonrecourse to OPG.
- $87 million of Senior Notes at year end 2020 related to Brighton Beach GS. The notes are secured by the assets of the Brighton Beach GS and are nonrecourse to the Company.
- $123 million of long-term debt at year end 2020 related to Eagle Creek. The notes are secured by the assets of Eagle Creek and are nonrecourse to the Company.
- $370 million of long-term debt at year end 2020 related to Cube Hydro. The notes are secured by the assets of Cube Hydro and are nonrecourse to the Company.

Maturity Profile							
(CAD millions - as at December 31, 2020)	**2021**	**2022**	**2023**	**2024**	**2025**	**Thereafter**	**Total**
Long-Term Debt	439	206	73	616	579	7,428	**9,341**
	5%	2%	1%	7%	6%	80%	**100%**

- OPG's maturity profile is fairly spread out.

Credit Facilities				
(CAD millions - as at December 31, 2020)	**Maturity**	**Amount**	**Drawn/LOC**	**Available**
Committed credit facility	May 2023	50	0	50
Committed credit facility	May 2024	950	0	950
Committed credit facility - USD 750 million	Nov. 2021	955	0	955
Non-revolving term facility[1]	Mar. 2021	600	0	600
OEFC general corporate credit facility	Dec. 2021	800	500	300
Short-term uncommitted credit facilities	Demand	655	536	119
Short-term uncommitted overdraft facilities	Demand	25	0	25
Lower Mattagami River Project - Tranche 2[2]	Aug. 2022	100	0	100
Lower Mattagami River Project - Tranche 1[2]	Aug. 2024	300	55	245
UMH Energy Partnership credit facilities[2]	Oct. 2021	16	16	0
UMH Energy Partnership overdraft facilities[2]	Oct. 2021	8	0	8
Eagle Creek credit facility - USD 10 million[2]	Aug. 2022	13	0	13
Eagle Creek credit facility - USD 20 million[2]	Oct. 2028	25	0	25
Subtotal		**4,497**	**1,107**	**3,390**
CPs issued - Corporate			919	(919)
CPs issued - LMELP			131	(131)
Total		**4,497**	**2,157**	**2,340**

1 Repayment of advances permanently reduce the amount of the credit facility. This facility expired as at March 31, 2021.
2 Nonrecourse to OPG as debt is secured by assets of the associated project.

- OPG has a reasonable liquidity profile.
- The Company has a $1.0 billion Canadian CP program ($575 million of CP outstanding as at December 31, 2020) and a USD 750 million CP program in the United States (USD 270 million of CP outstanding as at December 31, 2020; unrated by DBRS Morningstar). These CP programs are supported by the following facilities:
  - Two tranches of bank facilities totalling $1.0 billion;
  - A USD 750 million bank facility (due date of November 2021, with a one year term-out option); and
  - An OEFC facility (due date of December 2021) with available capacity of $300 million as of December 31, 2020.
- As at December 31, 2020, OPG had issued $536 million in letters of credit (LOC) under its corporate facilities of which $428 million was attributed to its supplementary pension plan.
- OPG also has a nonrevolving term facility of $1.0 billion maturing in March 2021; $400 million was drawn and repaid in 2020, leaving $600 million of available capacity.

- The LMELP, UMH, and Cube Hydro facilities are used to support the respective projects and are nonrecourse to OPG.

Company Profile

Generation Profile

As at December 31, 2020	Percent (%)	Capacity (MW)
Nuclear		
Darlington	14	2,634
Pickering A	5	1,030
Pickering B	11	2,064
	30	**5,728**
Thermal		
Atikokan (Biomass)	1	205
Brighton Beach	3	570
Halton Hills	4	683
Napanee	5	900
Portlands Energy Centre	3	562
Lennox (Dual oil & gas)	11	2,100
	27	**5,020**
Hydroelectric		
Nonregulated[1]	9	1,688
Regulated1	34	6,420
	43	**8,108**
Other		
Solar[2]	0	54
Total Capacity	**100**	**18,910**

1 Represents OPG's share of in-service generation.
2 Three solar facilities.

- OPG is the largest generator of electricity in Ontario.
- In 2020, the Company generated 82.1 terawatt hours of electricity with total in-service capacity of 18,910 MW as at December 31, 2020.
  - The increase in generating capacity can be attributed to the acquisition to the acquisition of the Halton Hills GS, Napanee GS, and the remaining 50% interest in the Portlands Energy Centre.
- OPG partnerships consist of the following:
  - OPG owns the Bruce A and Bruce B Nuclear GS, which are leased on a long-term basis to Bruce Power L.P. (rated BBB with a Stable trend by DBRS Morningstar).
  - OPG and the Lac Seul First Nation (LSFN) jointly own the Lac Seul GS, with LSFN owning 25% of the facility.
  - OPG and the Moose Cree First Nation (MCFN), through its wholly owned subsidiary, Amisk-oo-Skow Finance Corporation, jointly own the Little Long, Harmon, Kipling, and Smoky Falls GS, with MCFN owning 25% of the facilities.

- OPG and Coral Rapids Power Corporation (CRP), a wholly owned subsidiary of the Taykwa Tagamou Nation, jointly own PSS GS, with CRP owning 33% of the facility.
- OPG, a subsidiary of the Six Nations of the Grand River Development Corporation, and Mississauga's of the Credit First Nation jointly own the Nanticoke Solar facility, with OPG owning 80% of the facility.

Balance Sheet

(CAD millions)	Dec. 31	Dec. 31	Dec. 31		Dec. 31	Dec. 31	Dec. 31
Assets	**2020**	**2019**	**2018**	**Liabilities & Equity**	**2020**	**2019**	**2018**
Cash & equivalents	889	648	349	Short-term borrowings	1,062	178	322
Accounts receivable	492	468	483	Accounts payable	1,245	1,095	1,170
Inventories	328	325	397	Current portion L.T.D.	439	693	368
Regulatory assets	533	486	490	Regulatory liabilities	266	103	36
Prepaid expenses & other	313	320	419	Deferred revenue & other	0	0	37
Total Current Assets	**2,555**	**2,247**	**2,138**	**Total Current Liabilities**	**3,012**	**2,069**	**1,933**
Net fixed assets	29,810	26,047	22,987	Long-term debt	8,928	7,574	7,188
Intangibles	633	471	363	Deferred income taxes	1,379	1,154	1,018
Financing receivables	0	0	1,788	Pension & post-retirement benefits	8,411	6,667	6,339
Nuclear removal/waste management funds	19,050	18,252	17,464	Nuclear removal/waste management funds	22,947	22,081	21,225
Regulatory assets	8,571	6,770	6,769	Regulatory liabilities	1,239	949	762
Investments & other	1,454	1,617	743	Payables & other long-term liabilities	625	635	660
				Shareholders' equity	15,532	14,275	13,127
Total Assets	**62,073**	**55,404**	**52,252**	**Total Liabilities & SE**	**62,073**	**55,404**	**52,252**

Ratios

	For the year ended December 31				
Balance Sheet & Liquidity & Capital Ratios	**2020**	**2019**	**2018**	**2017**	**2016**
Current ratio	0.85	1.09	1.11	0.79	0.73
Total debt in capital structure (%)	40.2	37.2	37.5	35.6	34.4
Total debt in capital structure (%)[1, 2, 3]	33.8	28.6	26.9	26.2	34.3
Cash flow/Total debt (%)	31.8	30.4	28.0	26.4	40.4
Cash flow/Total debt (%)[1, 2]	39.3	41.7	45.0	40.0	40.6
(Cash flow - dividends)/Capex (times)	1.88	1.25	1.05	0.94	1.23
(Cash flow - n.w.f.)/Total debt (%)[1, 2, 5]	36.3	39.0	39.3	33.7	32.9
Dividend payout ratio (%)	0.0	0.0	103.3	0.0	0.0
Coverage Ratios (times)					
EBIT gross interest coverage[4]	2.73	1.23	0.77	(0.13)	(0.17)
EBIT gross interest coverage[1, 2, 4]	3.66	0.86	1.00	(0.24)	(0.14)
EBITDA gross interest coverage[4]	5.91	4.34	3.38	2.17	4.05
Fixed-charges coverage[4]	2.73	1.23	0.77	(0.13)	(0.17)
Profitability Ratios					
EBITDA margin (%)[4]	34.0	24.8	18.4	12.4	21.4
EBIT margin (%)[4]	15.7	7.0	4.2	-0.7	-0.9
Profit margin (%)[4]	9.4	7.8	4.9	-0.3	-1.9
Return on equity (%)[4]	4.6	3.4	2.2	-0.1	-1.0
Return on capital (%)[1, 3, 4]	3.7	2.5	1.8	0.5	0.1

1 Including operating leases.
2 Excludes nonrecourse debt.
3 Adjusted for Accumulated Other Comprehensive Income.
4 Excluding earnings from nuclear fixed asset removal and nuclear waste management funds.
5 Includes nuclear waste funding (n.w.f.) payments as they are not discretionary.

Rating History

	Current	2020	2019	2018	2017	2016
Issuer Rating	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Unsecured Debt	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

Commercial Paper Limit

- $1.0 billion and USD 750 million.

Previous Actions

- DBRS Morningstar Assigns Rating of A (low) With Stable Trend to Ontario Power Generation Inc.'s $500 Million Series 9 Medium-Term Notes, February 5, 2020.
- DBRS Morningstar Assigns Rating of A (low) with Stable Trends to Ontario Power Generation Inc.'s $400 Million Series 8 Medium-Term Notes, October 22, 2020.
- DBRS Morningstar Assigns Ratings of A (low) with Stable Trends to Ontario Power Generation Inc.'s $400 Million Series 6 and $800 Million Series 7 Medium-Term Notes, April 9, 2020.
  DBRS Morningstar Confirms Ontario Power Generation Inc. at A (low)/R-1 (low), Stable Trends, April 7, 2020.

Previous Report

- Ontario Power Generation Inc.: Rating Report, April 16, 2020.

About DBRS Morningstar

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Rating Report
Ontario Power Generation Inc.

DBRS Morningstar
April 25, 2022

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Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A (low)	Confirmed	Stable
Unsecured Debt	A (low)	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

On April 8, 2022, DBRS Limited (DBRS Morningstar) confirmed the Issuer Rating and Unsecured Debt rating of Ontario Power Generation Inc. (OPG or the Company) at A (low) and the Commercial Paper (CP) rating at R-1 (low). All trends are Stable. The ratings of OPG are underpinned by its regulated electricity generation business under the Ontario Energy Board (OEB). The Stable trend reflects the steady cash flows generated by those assets as well as the Company's reasonable key credit metrics.

In November 2021, the OEB approved OPG's application for 2022 to 2026 regulated payment amounts. As per *Ontario Regulation (O. Reg.) 53/05*, OPG's regulated hydroelectric payment amounts will be frozen at 2021 levels for 2022–26. Payment amounts for regulated nuclear operations were determined largely through a continuation of the previous Custom Incentive Rate-setting (IR) framework. The OEB approved the Company's settlement proposal as filed, including a regulated nuclear revenue requirement of $16.0 billion and in-service capital additions of $8.6 billion over the five-year term. While the OEB disallowed $94 million of capital amounts already in-service, and OPG agreed to a 3% annual reduction to its non-Darlington-Refurbishment-related regulated nuclear operations, maintenance, and administration (OM&A) budget (total of $277 million over the five-year term), overall, DBRS Morningstar considers the approval to be positive for the Company. The approval should provide stability for OPG's operations as well as certainty for the recovery of the remaining $6.4 billion of capital expenditures (capex) planned for the Darlington Refurbishment project (total capex of $12.8 billion). The Company has noted that the Darlington Refurbishment project remains on schedule and is tracking budget. However, should there be significant cost overruns that result in stranded costs, a negative rating action may occur.

OPG's earnings and cash flows decreased in 2021 because of lower nuclear generation as (1) planned outages in 2020 were delayed to 2021 in response to the Coronavirus Disease (COVID-19) pandemic, which contributed to higher earnings for 2020, and (2) Unit 3 of the Darlington Nuclear Generating Station (GS) was out for refurbishment. The Company's key credit metrics were strong for the current ratings and are expected to remain supportive even as debt increases moderately over the near term to fund the Darlington Refurbishment and other capex projects. DBRS Morningstar notes that a positive

rating action is unlikely given OPG's business profile and the ongoing significant capex needs. However, a negative rating action may occur should key credit metrics deteriorate to a level no longer commensurate with the current rating category.

Financial Information

	For the year ended December 31				
	2021	**2020**	**2019**	**2018**	**2017**
Cash flow/Total debt (%)[1, 2]	40.6	39.3	41.7	45.0	40.0
Total debt in capital structure (%)[1, 2, 3]	30.2	33.8	28.6	26.9	26.2
EBIT gross interest coverage (times)[1, 2, 4]	2.43	3.66	0.86	1.00	(0.24)
(Cash flow – n.w.f.)/Total debt (%)[1, 2, 5]	37.0	36.3	39.0	39.3	33.7

1 Including operating leases.
2 Excludes nonrecourse debt.
3 Adjusted for Accumulated Other Comprehensive Income.
4 Excluding earnings from nuclear fixed asset removal and nuclear waste management funds.
5 Includes nuclear waste funding (n.w.f.) payments as they are not discretionary.

Issuer Description

OPG is an electricity generation company with a diverse portfolio of approximately 19,000 megawatts (MW) of in-service generating capacity. The Company is wholly owned by the Province of Ontario.

Rating Considerations

Strengths

1. Reasonable regulatory framework that provides stable cash flow

The reasonable regulatory framework has allowed the Company to recover prudently incurred costs and provided stable cash flows. DBRS Morningstar notes, however, that there have been disallowances by the OEB in the past on labour compensation costs related to OPG's nuclear operations. DBRS Morningstar also notes that, under an IR framework and the regulated hydroelectric rate freeze, OPG's profitability could come under further pressure because of the need to meet efficiency and productivity benchmarks.

2. Support of shareholder (the Province)

The Province indirectly provides OPG with some of its long-term funding requirements through the Ontario Electricity Financial Corporation (OEFC; rated AA (low) with a Stable trend by DBRS Morningstar), a government financing arm for provincial power companies. DBRS Morningstar believes that the Province will continue to support its investment because OPG is a creation of the Province and is integral to fulfilling Ontario's energy needs. OPG's importance in Ontario is also demonstrated by the fact that it is the primary electricity generator in the province, accounting for approximately 53% of electricity produced in 2021.

DBRS Morningstar notes that OPG's debt is not directly guaranteed by the Province. As at December 31, 2021, OPG had approximately $2.7 billion of notes payable to the OEFC, comprising 27% of the Company's outstanding debt. While this financial support does not, in itself, result in any uplift to the

Company's ratings, the ratings do incorporate DBRS Morningstar's belief that the Province will, in exceptional circumstances, provide support to OPG.

3. Limited nuclear waste management liabilities

As a result of the Ontario Nuclear Funds Agreement with the Province, OPG's exposure to the costs to dispose of the initial 2.23 million used fuel bundles produced has been capped at $5.94 billion (in 1999 dollar terms). The used fuel obligation is funded by the used fuel fund, which was fully funded as at December 31, 2021. The Province provides a guarantee for any shortfall between the value of the nuclear fund and the Canadian Nuclear Safety Commission consolidated financial guarantee requirement.

Challenges

1. Significant capex program

OPG has a significant capex program underway (approximately $3.2 billion planned for 2022). The Company also faces significant execution risk as well as the potential for cost overruns associated with the Darlington Refurbishment because of the project's complexity and scale. While DBRS Morningstar is encouraged because the first unit of the Darlington Refurbishment was completed on budget and on schedule, there are still three more units to be refurbished. DBRS Morningstar expects that OPG will not undertake any major capex without having financing and a cost-recovery mechanism in place, thus minimizing financial risks.

2. Nuclear generation risks

Nuclear generation (approximately 51% of OPG's production in 2021) faces higher operating risks than other types of power generation because of its complex technology. The financial implications of forced outages, especially with older units (e.g., the Pickering Nuclear GS), are greater, given the high fixed-cost nature of these plants and because lost revenues resulting from outages are not recoverable through rates.

3. High cost base

OPG's high cost base has resulted in several disallowances by the OEB. For the 2022–26 rates decision, the Company agreed, in a settlement proposal with intervenors, to reduce its non-Darlington-Refurbishment-related regulated nuclear OM&A budget by 3% annually (total of $277 million over the five-year term). DBRS Morningstar believes that OPG's inability to fully recover compensation costs in future regulated prices could have a negative impact on earnings and affect the Company's ability to achieve its approved return on equity (ROE). DBRS Morningstar notes that OPG has been combatting this issue through its cost-reduction and efficiency-improvement initiative, which has saved $1.0 billion through a reduction in headcount of over 2,800 since 2011.

4. Political intervention

OPG is subject to political intervention, largely because of its ownership by the Province and changes in government mandates and policies. DBRS Morningstar notes that, though the Province has committed to having the Company run more autonomously, the risk of further government intervention still exists.

In November 2020, the Province amended legislation to freeze OPG's hydroelectric rates at the 2021 level for the next regulatory period of 2022–26. DBRS Morningstar expects the Company's earnings to be modestly pressured as OPG will have to find efficiencies to offset inflationary cost increases.

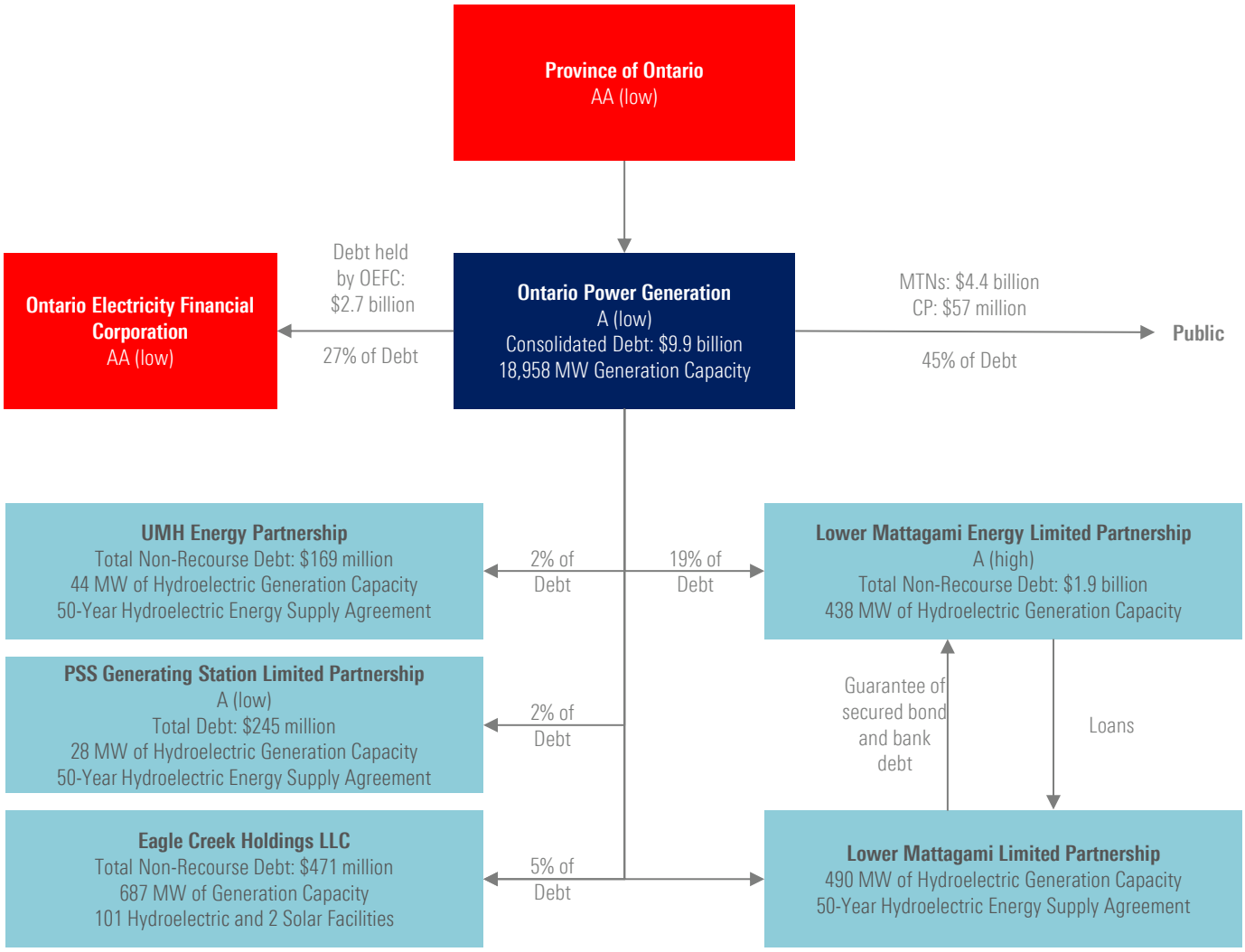
5. Increased exposure to nonregulated operations

OPG has in recent years acquired multiple nonregulated generation assets, including gas-fired plants in Ontario and two renewable facility operators in the U.S. (Eagle Creek Renewable Energy LLC (Eagle Creek) and Cube Hydro Partners, LLC (Cube Hydro)). The Company also owns nonregulated natural gas, oil, solar, and biomass generation assets in the province. While the Ontario assets are largely under long-term contracts with strong investment-grade counterparties (such as the Independent Electricity System Operator (IESO)) and contribute relatively stable earnings and cash flow, DBRS Morningstar does view nonregulated assets as generally having higher business risks than the incumbent regulated operations because there is less cost recovery certainty and potentially more volatile cash flow.

Following the acquisition of three Ontario natural gas-fired assets in 2020, earnings contributed by nonregulated operations is expected to remain moderate at below 20% over the long term. DBRS Morningstar notes, however, earnings contributed by regulated operations may fluctuate over the near term resulting in nonregulated earnings to be near the 20% threshold as the ongoing Darlington Refurbishment project constricts output. The Company has indicated that growth in its nonregulated business will be at a more moderate pace following the above-mentioned acquisitions, with most planned capex for its regulated operations. As such, contributions from regulated operations are expected to remain above 80% over the long term, especially once the Darlington Refurbishment is completed in 2026. Additionally, DBRS Morningstar also considers assets under regulatory-styled contracts (such as Lower Mattagami Energy Limited Partnership (LMELP; rated A (high) with a Stable trend by DBRS Morningstar), PSS Generating Station Limited Partnership (PSS; rated A (low) with a Stable trend by DBRS Morningstar), and UMH Energy Partnership (UMH; not rated by DBRS Morningstar)) to have similar credit risks as regulated operations because those contracts mimic the current regulatory construct under the OEB (DBRS Morningstar estimates an EBITDA contribution of 84% from regulated operations and assets under regulatory-styled contracts in 2021). However, should OPG pursue acquisitions that result in a significant shift in the EBITDA mix between regulated and nonregulated operations or lead to credit metrics deteriorating to a level no longer supportive of the current rating category, DBRS Morningstar may take negative rating action.

Organizational Chart

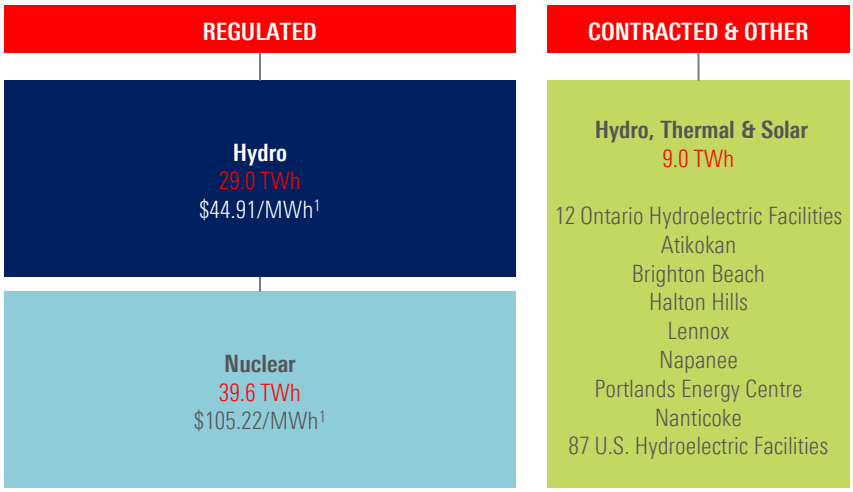
Simplified Organizational Chart



As at December 31, 2021.
Source: OPG.

- As at December 31, 2021, debt at the OPG corporate level consists of $2.7 billion held by the OEFC, $4.4 billion of medium-term notes (MTNs), and $57 million of CP outstanding.
  - Debt at UMH, LMELP, and Eagle Creek are secured by the assets at each corresponding subsidiary and are nonrecourse to OPG.
  - Debt at PSS GS is recourse to OPG until the recourse release date.
- In 2021, OPG merged the operations of Eagle Creek with Cube Hydro and its affiliate Helix Partners, LLC; the combined entity will operate under the Eagle Creek Renewable Energy name.

Price Structure



1 Rates as of January 1, 2022.
For the year ended December 31, 2021.
Source: OPG.

- OPG sells electricity to consumers through the IESO.
- Regulated facilities sell at rates set by the OEB, which could include rate riders used for the recovery of nuclear deferral and hydroelectric variance account balances.
- The Contracted and Other Portfolio includes (1) assets in Ontario that sell electricity at prices set through Energy Supply Agreements (ESA) or other long-term contracts with the IESO and (2) Eagle Creek, which holds interest in 101 hydroelectric GS and two solar facilities throughout the U.S.
  - The Eagle Creek and Cube Hydro facilities either sell into the merchant market or operate under long-term energy or capacity supply contracts.

Major Projects

Project	Estimated Cost (CAD millions)	Spent as of Dec. 31, 2021 (CAD millions)	In-Service Target Date
Darlington Refurbishment	12,800	8,259	2026[1]
Little Long Dam Safety Project	650	317	2023
Smoky Falls Dam Safety Project	390	33	2025
Sir Adam Beck I GS Units G1 and G2 Replacement	128	93	2022
Calabogie Hydroelectric GS	145	89	2022
Ranney Falls Hydroelectric GS	77	72	2022

1 Four units with staged in-service. Last unit scheduled to be completed by 2026.

- **Darlington Refurbishment**: The Darlington Refurbishment will extend the operating life of the Darlington Nuclear GS by approximately 30 years. The execution of the refurbishment of the first unit began in October 2016, and the last unit is scheduled to be completed by 2026. Construction on the first unit was completed in March 2020 and returned in service in June 2020. Refurbishment on the second unit

began in September 2020 after a short delay related to the coronavirus pandemic. Refurbishment on the third unit began in February 2022. The project remains on schedule and on budget.

- **Little Long Dam Safety Project**: This project is intended to make reliability and operational improvements and increase the discharge capacity at the Little Long Dam. The Little Long Dam supports hydroelectric GSs on the Lower Mattagami River.
- **Smoky Falls Dam Safety Project**: This project is intended to improve dam safety at the Smoky Falls hydroelectric GS.
- **Sir Adam Beck 1 GS Units G1 and G2 Replacement**: This project is intended to replace two older generators at the Sir Adam Beck 1 GS, adding 125 MW of incremental capacity.
- **Calabogie Hydroelectric GS**: This project is intended to redevelop the Calabogie GS by replacing the powerhouse to 11 MW from 5 MW.
- **Ranney Falls Hydroelectric GS**: This project will replace an existing generation unit at Ranney Falls with a 10-MW single-unit powerhouse. While construction was completed in 2019, the unit was damaged during commissioning. The vendor will disassemble, repair, and reassemble the unit at its own cost.
- In December 2021, Eagle Creek acquired a 48-MW Racine Hydroelectric GS located in Ohio for approximately $112 million.

Regulation

- OPG benefits from a reasonably regulated environment. As at December 31, 2021, approximately 64% of its installed in-service capacity is regulated.
- OPG, regulated by the OEB under the Electricity Restructuring Act, 2004 (Ontario), is allowed to receive regulated prices for all electricity generated from its nuclear facilities (5,728 MW) as well as most of its hydroelectric power facilities (6,420 MW).
- In December 2017, the OEB issued its decision on OPG's application for rates effective January 1, 2017.
    - The OEB approved rates to be effective June 1, 2017, rather than the applied-for effective date of January 1, 2017.
    - Capital structure will remain at 55% debt (the Company had requested a change to 51% debt) and an allowed ROE of 8.78%. The ROE will not be updated throughout the five-year term.
    - For hydroelectric facilities, the Price Cap IR methodology is used. Under Price Cap IR, rates for the hydroelectric facilities are subject to a formula price cap that allows for an annual increase in the payment amount based on inflation less productivity and a utility-specific stretch factor, which can be reset annually (productivity factor of 0%, stretch factor of 0.3%).
    - Under Price Cap IR, OPG could file an Incremental Capital Module application to potentially recover any material and necessary prudently spent incremental capex during the IR period of five years. Additionally, the Company could ask to initiate a regulatory review of its application if actual ROE falls 300 basis points below the approved ROE.
    - For nuclear facilities, OPG requested the use of a Custom IR methodology and a rate-smoothing deferral account. Under its Custom IR methodology, nuclear revenue requirements were determined by a five-year forecast cost-of-service (COS) approach, but with a stretch factor of 0.6% applied to the Company's OM&A expenditures. The reduction in OM&A costs as a result of the stretch factor will accumulate for the five-year period. The rate-smoothing deferral account (as required under O. Reg. 53/05) will stabilize year-to-year changes to weighted-average payment

amounts as the Darlington Refurbishment continues. OPG will defer a portion of its approved nuclear revenue requirements into the rate-smoothing deferral account and will be allowed to recover the deferred amount, and any amount to be deferred from 2022 to 2026, over a 10-year period once the Darlington Refurbishment has been completed.
    - The OEB reduced the nuclear OM&A budget by $100 million per year for a total of $500 million over five years. Additionally, the OEB did not approve a mid-term review (prior to July 1, 2019) to update the nuclear production forecast.
    - The OEB approved the inclusion of $5.5 billion to the rate base over the five-year period of the Custom IR for the Darlington Refurbishment. Any cost overruns will be subject to a prudence review before being added to the rate base.
    - The OEB also approved the recovery of balances as at December 31, 2015, in OPG's deferral and variance accounts.
- In December 2020, the OEB approved the Company's Application for the 2021 Hydroelectric Payment Amount Adjustment to be effective January 1, 2021.
    - The OEB approved a 1.7% base rate increase based on an inflation factor of 2.0%.
- In November 2020, the Province amended O. Reg. 53/05 to freeze hydroelectric rates for OPG at the 2021 level for the next regulatory period of 2022–26.
    - Rates for nuclear facilities will not be frozen and will continue to be set by the OEB.
    - DBRS Morningstar notes the hydroelectric rate freeze may modestly pressure the Company's earnings as OPG will have to find efficiencies in its regulated hydroelectric operations to offset inflationary cost increases.
- In November 2021, the OEB issued its decision on OPG's application for rates effective January 1, 2022.
    - The OEB approved a settlement proposal between OPG and intervenors as filed.
    - As per O. Reg. 53/05, hydroelectric base payment amounts will remain at the 2021 level.
    - Capital structure will remain at 55% debt (the Company had requested a change to 50% debt) and an allowed ROE of 8.66%.
    - For nuclear facilities, the continuation of the current Custom IR methodology with the stretch factor at 0.6% for 2023–25 (compared with 0.45% as requested), and 0.3% for 2026.
    - Total regulated nuclear revenue requirement of $16.0 billion over the five-year term, representing a $567 million reduction (including a 3%, or $277 million, reduction of OM&A costs) from the Company's application.
    - The OEB approved the inclusion of $8.6 billion to the rate base (including $6.4 billion for the Darlington Refurbishment) over the five-year period of the Custom IR (reduction of $298 million for planned non-Darlington Refurbishment in-service capital add-ons). Any cost overruns associated with the Darlington Refurbishment will be subject to a prudence review before being added to the rate base.
    - Inclusion of $396 million to the rate base for the Heavy Water Storage and Drum Handling Facility project (in-service 2020); this represents a permanent rate base reduction for the project of $94 million plus carrying costs incurred from May 2017 to March 2020 for capital cost deemed not prudently incurred.

- Recently completed non-Darlington Refurbishment capex of $358 million, which exceeded the 2017–21 approved in-service capital additions, will earn an ROE at the cost of long-term debt (3.6%) instead of the allowed ROE until 2037.
- The OEB approved the recovery of balances as at December 31, 2019, in OPG's deferral and variance accounts. The OEB also approved a $47 million credit to customers for the impact of favourable electricity revenue during the 2020 and 2021 coronavirus pandemic response (net of any incremental pandemic-related OM&A).
- All previously existing regulatory accounts will continue, along with new accounts to track (1) any financial impact from a possible transition to and implementation of IFRS from US GAAP, (2) revenue requirement impact for a planned new corporate campus, and (3) any revenue requirement impact to nuclear liabilities and depreciation expense from accounting end-of-life assumptions for the Pickering GS.
- An earnings-sharing mechanism was also approved, where regulated earnings 100 basis points above the approved ROE over the cumulative five-year term will be shared 50-50 with customers.

Approved Regulated Nuclear Amounts	2022	2023	2024	2025	2026
Nuclear revenue requirement (CAD millions)	3,515.5	3,430.0	3,518.3	3,197.6	2,439.5
Nuclear rate base (CAD millions)	8,600.3	8,615.0	11,033.4	12,188.8	12,991.8
Nuclear payment amount (CAD per megawatt hour (MWh)	105.22	109.04	104.63	108.19	118.91
Hydro payment amount (CAD per MWh)	44.91	44.91	44.91	44.57	44.57

Assessment of Regulatory Framework

Criteria	Score	Analysis
1. Deemed Equity	Excellent **Good** Satisfactory Below Average Poor	The OEB allows OPG to have a deemed equity of 45%.
2. Allowed ROE	Excellent Good **Satisfactory** Below Average Poor	OPG has an allowed ROE of 8.66% for 2022–26, which is in line with the other regulated utilities in Ontario. Any difference in ROE between the Company and other regulated utilities in the province is mainly because of the timing of the regulatory filings and the interest environment prevalent at that time.
3. Energy Cost Recovery	Excellent Good Satisfactory Below Average Poor	N/A; energy costs are recovered through rates for OPG.
4. Capital and Operating Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	Under Custom IR for the nuclear facilities, the capex program for OPG is preapproved for a five-year period by the OEB and recovered through base rates. Future test years are utilized nuclear rates applications. Some volume risk exists, but this is partly mitigated by (1) use of deferral accounts for volumetric differences, and (2) rates are based on forecasts which include scheduled outages. However, lost revenues resulting from forced outages are not recoverable through rates.
5. COS versus IRM	Excellent Good **Satisfactory** Below Average Poor	The nuclear facilities operate under Custom IR, which is a hybrid of COS and the IR framework, for a five-year term. DBRS Morningstar considers the inflation, productivity (0%), and stretch (0.6%) factors as reasonable.
6. Political Interference	Excellent Good Satisfactory **Below Average** Poor	The Government of Ontario plays a significant role in the electricity sector in Ontario, given that most of the utilities are government owned (OPG is owned by the Province). Furthermore, stakeholders, such as the IESO, are also government owned. As a result, the government has direct and indirect influence on Ontario's electricity industry.
7. Stranded Cost Recovery	Excellent Good **Satisfactory** Below Average Poor	Regulated utilities in Ontario have a limited history of stranded costs. Most prudently incurred or budgeted capex is approved by the OEB. While OPG has seen some write-downs, these have been because the OEB had deemed the costs overruns to have been imprudent.
8. Rate Freeze	Excellent Good Satisfactory **Below Average** Poor	DBRS Morningstar notes that, in November 2020, the Province amended O. Reg. 53/05 to freeze hydroelectric rates for the Company at the 2021 level for the next regulatory period from 2022 to 2026. Rates for nuclear facilities will not be frozen and will continue to be set by the OEB. DBRS Morningstar notes that the hydroelectric rate freeze may modestly pressure OPG's earnings as the Company will have to find efficiencies to offset inflation.

Earnings and Outlook

	For the year ended December 31				
(CAD millions where applicable)	**2021**	**2020**	**2019**	**2018**	**2017**
Revenues	6,877	7,240	6,022	5,535	5,158
EBITDA[1]	1,977	2,459	1,496	1,017	642
EBIT[1]	845	1,137	423	233	(37)
Gross interest expense	383	416	345	301	296
Earning before taxes[1]	655	835	439	225	(92)
Net income before nonrecurring items[1]	667	679	469	274	(14)
Reported net income	1,415	1,361	1,126	1,195	860
Return on equity (%)	4.1	4.6	3.4	2.2	-0.1
Segmented reported EBITDA					
Nuclear generation	1,210	1,917	1,306	863	488
Nuclear sustainability services	(110)	(113)	(113)	(117)	(150)
Regulated hydroelectric generation	898	874	843	748	753
Contracted and other generation	369	348	341	384	379
Atura Power	387	279	57	0	0
Reported subtotal	**2,754**	**3,305**	**2,434**	**1,878**	**1,470**
Corporate	194	87	36	337	394
Reported total	**2,948**	**3,392**	**2,470**	**2,215**	**1,864**
Hydroelectric rate base	N/A	N/A	N/A	N/A	N/A
Nuclear rate base	7,711	7,347	3,374	3,446	3,628
Approved regulated ROE (%)	8.78	8.78	8.78	8.78	8.78
Achieved regulated ROE (%)	N/A	17.22	15.72	10.69	5.88

1 Excluding earnings from nuclear fixed asset removal and nuclear waste management funds.

2021 Summary

- EBITDA and EBIT decreased substantially because of lower contributions from the regulated nuclear generation segment. Earnings decreased for that segment because of lower generation for the year with Unit 3 of the Darlington Nuclear GS out for refurbishment and planned cyclical maintenance of Units 1 and 4.
  - This was partly offset by lower depreciation, higher approved nuclear and hydroelectric base rates, higher wholesale electricity market prices for noncontracted U.S. generation assets, and a full year's contribution from the Atura Power assets acquired in April 2020.
- Net income before nonrecurring items was modestly lower because of lower interest expense from the lower debt load and lower income taxes.

2022 Outlook

- DBRS Morningstar expects OPG's net income in 2022 to be lower than in 2021.
  - Earnings from regulated nuclear generation are expected to be lower with both Units 1 and 3 of the Darlington Nuclear GS out for refurbishment, partly offset by higher approved rates.

- Earnings from regulated hydroelectric generation should remain stable despite the rate freeze.
- OPG also expects earnings from contracted generation assets and Atura Power to be stable.
- OPG expects overall net income to be stable in 2022, however, as the Company has executed agreements to sell two premises in 2022 for an estimated pre-tax gain of $148 million.

- Earnings volatility going forward will come from (1) forecast risk as part of the IR process, (2) macro factors such as weather, unexpected outages, and Ontario's economic conditions, and (3) variability in water flows and wholesale electricity prices for uncontracted facilities.

Financial Profile

	For the year ended December 31				
(CAD millions where applicable)	**2021**	**2020**	**2019**	**2018**	**2017**
Net income before nonrecurring items[4]	667	679	469	274	(14)
Depreciation & amortization	1,132	1,322	1,073	784	679
Deferred income taxes and other	1,381	1,315	1,026	1,147	1,070
Cash flow (before working capital changes)	**3,180**	**3,316**	**2,568**	**2,205**	**1,735**
Nuclear waste funding	(458)	(439)	(336)	(307)	(313)
Dividends paid	0	0	0	(283)	0
Capital expenditures	(2,025)	(1,765)	(2,058)	(1,826)	(1,853)
Free cash flow (before working capital changes)	**697**	**1,112**	**174**	**(211)**	**(431)**
Changes in noncash working cap. items	59	103	99	(160)	80
Change in regulatory assets/liabilities	(251)	(156)	275	(51)	(558)
Net free cash flow	**505**	**1,059**	**548**	**(422)**	**(909)**
Long-term investments	(112)	(2,814)	(1,232)	(358)	0
Proceeds on asset sales	0	0	11	289	554
Acquisition of Fair Hydro Trust receivables	0	0	0	(609)	(1,179)
Change in Fair Hydro Trust debt	0	0	0	306	601
Net equity change	0	0	0	268	519
Net debt change	(527)	1,993	866	622	458
Other	197	(11)	(8)	(17)	4
Change in cash	**63**	**227**	**185**	**79**	**48**
Total debt[2]	7,353	7,928	5,729	4,730	4,053
Cash flow/Total debt (%)[1, 2]	40.6	39.3	41.7	45.0	40.0
Total debt in capital structure (%)[1, 2, 3]	30.2	33.8	28.6	26.9	26.2
EBIT gross interest coverage (times)[1, 2, 4]	2.43	3.66	0.86	1.00	(0.24)
(Cash flow—n.w.f.)/Total debt (%)[1, 2, 5]	37.0	36.3	39.0	39.3	33.7

1 Including operating leases.
2 Excludes nonrecourse debt.
3 Adjusted for Accumulated Other Comprehensive Income.
4 Excluding earnings from nuclear fixed asset removal and nuclear waste management funds.
5 Includes nuclear waste funding (n.w.f.) payments as they are not discretionary.

2021 Summary

- OPG's key credit metrics exclude nonrecourse debt from UMH, LMELP, and Eagle Creek.

  - The Company's adjusted cash flow-to-debt and debt-to-capital metrics were stable for the year. The EBIT-interest coverage ratio weakened, however, because of lower EBIT.
  - Overall, OPG's key credit metrics remained supportive of the current ratings.
- Cash flow from operations decreased because of lower cash receipts from regulated operations, partly offset by higher contributions from a full year's operations of Atura Power.
- Capex increased to $2.0 billion because of continued spending for the Darlington Refurbishment, redevelopment of the Calabogie GS, work on the Little Long Dam Safety project, and remediation at the Napanee GS, which were recovered from the seller.
  - In total, OPG received proceeds of $220 million as part of the settlement related to the acquisition of the natural gas-fired assets.
- Long-term investments of $112 million represent the acquisition of Racine Hydroelectric GS by Eagle Creek in December 2021.
- OPG generated a positive net free cash flow in 2021, proceeds of which were used for the Racine Hydroelectric GS acquisition and to repay outstanding CPs and $185 million of debt held by the OEFC.
  - OPG also issued $500 million of Senior Notes under the MTN program to repay outstanding CPs.
  - Additionally, LMELP issued $375 million of green bonds to refinance $225 million of bonds at maturity and to fund the Little Long Dam Safety project.

2022 Outlook

- DBRS Morningstar expects OPG's key credit metrics to weaken in 2022 but remain in line with the current ratings.
  - DBRS Morningstar expects both the Company's adjusted cash flow-to-debt and EBIT-interest coverage ratios to weaken in 2022 because of lower earnings for the year. However, both ratios should remain supportive of the current ratings.
  - Debt-to-capital for OPG is expected to see a modest increase from debt to be issued to fund the significant capex program.
- OPG has forecast capex to increase substantially to $3.2 billion for 2022 largely because of work on both Units 1 and 3 of the Darlington Refurbishment and work on the Little Long Dam Safety project.

Long-term Debt and Credit Facilities

Long-term Debt

(CAD millions)	Maturity	Dec. 31, 2021	Dec. 31, 2020
Notes payable to the OEFC	2022–48	2,690	2,875
Medium Term Note Program	2025–51	4,350	3,850
UMH Energy Partnership[1]	2041	169	172
PSS Generating Station Limited Partnership[2]	2067	245	245
Lower Mattagami Energy Limited Partnership[1]	2024–52	1,745	1,595
Brighton Beach Power Limited Partnership[1]		0	86
Eagle Creek[1]	2025–35	471	493
Other		25	25
Subtotal		**9,695**	**9,341**
Less: Fair value discount		10	24
Less: Bond issuance fees		(39)	(33)
Less: Current portion		(179)	(439)
Total long-term debt		**9,487**	**8,893**

1 Nonrecourse to OPG as debt is secured by assets of the associated project.
2 Secured by assets of the project; recourse to OPG until the recourse release date.

- In February 2021, OPG issued $500 million of Senior Notes maturing in 2051 at a coupon rate of 2.95%.
- The amortizing UMH notes were issued in 2009 with a maturity date of 2041 and an effective interest rate of 7.86%. The notes are secured by the assets of the Upper Mattagami and Hound Chute project and are nonrecourse to OPG.
- The amortizing PSS GS notes were issued in 2015 with a maturity date of 2067 and an effective interest rate of 4.90%. The notes are secured by the assets of PSS GS and are recourse to OPG until the recourse release date (expected in 2022).
- The LMELP notes are secured by the assets of the project and are nonrecourse to OPG.
  - In May 2021, LMELP issued $375 million of Senior Secured Bonds maturing in 2031 at a coupon rate of 2.43%. Proceeds from the issuance were partly used to repay a $225 million bond maturity.
- In June 2021, OPG fully repaid $81 million of Senior Notes outstanding related to Brighton Beach GS. These notes were secured by the assets of the Brighton Beach GS and were nonrecourse to the Company.
- $471 million of long-term debt at year end 2021 related to Eagle Creek. The notes are secured by the assets of Eagle Creek and are nonrecourse to the Company.

Maturity Profile

(CAD millions—as at December 31, 2021)	2021	2022	2023	2024	2025	Thereafter	Total
Long-Term Debt	179	44	607	579	675	7,611	**9,695**
	2%	0%	6%	6%	7%	79%	**100%**

- OPG's maturity profile is fairly spread out.

Credit Facilities

(CAD millions—as at December 31, 2021)	Maturity	Amount	Drawn/LOC	Available
Committed credit facility	May 2026	1,000	0	**1,000**
Committed credit facility—USD 750 million	Nov. 2022	951	0	951
OEFC general corporate credit facility	Dec. 2026	750	0	750
Short-term uncommitted credit facilities	Demand	655	459	196
Short-term uncommitted overdraft facilities	Demand	25	0	25
Lower Mattagami River Project[1]	Aug. 2026	400	55	345
UMH Energy Partnership credit facilities[1]	Oct. 2022	16	16	0
UMH Energy Partnership overdraft facilities[1]	Oct. 2022	8	0	8
Eagle Creek credit facility—USD 5 million[1]	Aug. 2022	6	0	6
Eagle Creek credit facility—USD 20 million[1]	Oct. 2028	25	0	25
Subtotal		**3,837**	**530**	**3,307**
CPs issued—Corporate			57	(57)
CPs issued—LMELP			125	(125)
Total		**3,837**	**712**	**3,124**

1 Nonrecourse to OPG as debt is secured by assets of the associated project.

- OPG has a reasonable liquidity profile.
- The Company has a $1.0 billion Canadian CP program ($57 million of CP outstanding as at December 31, 2021) and a USD 750 million CP program in the U.S. (none outstanding as at December 31, 2021; unrated by DBRS Morningstar). These CP programs are supported by the following facilities:
  - Committed bank facility of $1.0 billion (due date of May 2026);
  - A USD 750 million bank facility (due date of November 2022, with a one-year term-out option); and
  - An OEFC facility of $750 million (due date of December 2026).
- As at December 31, 2021, OPG had issued $459 million in letters of credit (LOC) under its corporate facilities of which $395 million was attributed to its supplementary pension plan.
- The LMELP, UMH, and Eagle Creek facilities are used to support the respective projects and are nonrecourse to OPG.

Company Profile

Generation Profile

As at December 31, 2021	Percent (%)	Capacity (MW)
Nuclear		
Darlington	14	2,634
Pickering A	5	1,030
Pickering B	11	2,064
	30	**5,728**
Thermal		
Atikokan (Biomass)	1	205
Brighton Beach	3	570
Halton Hills	4	683
Napanee	5	900
Portlands Energy Centre	3	562
Lennox (Dual oil & gas)	11	2,100
	26	**5,020**
Hydroelectric		
Nonregulated[1]	9	1,736
Regulated	34	6,420
	43	**8,156**
Other		
Solar[2]	0	54
Total Capacity	**100**	**18,958**

1 Represents OPG's share of in-service generation.
2 Three solar facilities.

- OPG is the largest generator of electricity in Ontario.
- In 2021, the Company generated 77.6 terawatt hours of electricity with total in-service capacity of 18,958 MW as at December 31, 2021.
  - The increase can be attributed to the acquisition of the Racine Hydroelectric GS.
- OPG partnerships consist of the following:
  - OPG owns the Bruce A and Bruce B Nuclear GS, which are leased on a long-term basis to Bruce Power L.P. (rated BBB with a Stable trend by DBRS Morningstar).
  - OPG and the Lac Seul First Nation (LSFN) jointly own the Lac Seul GS, with LSFN owning 25% of the facility.
  - OPG and the Moose Cree First Nation (MCFN), through its wholly owned subsidiary, Amisk-oo-Skow Finance Corporation, jointly own the Little Long, Harmon, Kipling, and Smoky Falls GS, with MCFN owning 25% of the facilities.
  - OPG and Coral Rapids Power Corporation (CRP), a wholly owned subsidiary of the Taykwa Tagamou Nation, jointly own PSS GS, with CRP owning 33% of the facility.

  OPG, a subsidiary of the Six Nations of the Grand River Development Corporation, and a subsidiary of Mississaugas of the Credit First Nation jointly own the Nanticoke Solar Facility, with OPG owning 80% of the facility.

ESG Checklist

ESG Factor		ESG Credit Consideration Applicable to the Credit Analysis: Y/N		Extent of the Effect on the ESG Factor on the Credit Analysis: Relevant (R) or Significant (S)*
Environmental		**Overall:**	**N**	**N**
	Emissions, Effluents, and Waste	Do we consider that the costs or risks for the issuer or its clients result, or could result, in changes to an issuerÆs financial, operational, and/or reputational standing?	**N**	**N**
	Carbon and GHG Costs	Does the issuer face increased regulatory pressure relating to the carbon impact of its or its clients' operations resulting in additional costs and/or will such costs increase over time affecting the long term credit profile?	**N**	**N**
	Resource and Energy Management	Does the scarcity of sourcing key resources hinder the production or operations of the issuer, resulting in lower productivity and therefore revenues?	**N**	**N**
	Land Impact and Biodiversity	Is there a financial risk to the issuer for failing to effectively manage land conversion, rehabilitation, land impact, or biodiversity activities?	**N**	**N**
	Climate and Weather Risks	In the near term, will climate change and adverse weather events potentially disrupt issuer or client operations, causing a negative financial impact? In the long term, will the issuer's or client's business activities and infrastructure be materially affected financially by a 2C rise in temperature?	**N**	**N**
Social		**Overall:**	**N**	**N**
	Social Impact of Products and Services	Do we consider that the social impact of the issuer's products and services could pose a financial or regulatory risk to the issuer?	**N**	**N**
	Human Capital and Human Rights	Is the issuer exposed to staffing risks, such as the scarcity of skilled labour, uncompetitive wages, or frequent labour relations conflicts that could result in a material financial or operational impact?	**N**	**N**
		Do violations of rights create a potential liability that can negatively affect the issue's financial wellbeing or reputation?	**N**	**N**
		Human Capital and Human Rights	**N**	**N**
	Product Governance	Does failure in delivering quality products and services cause damage to customers and expose the issuer to financial and legal liability?	**N**	**N**
	Data Privacy and Security	Has misuse or negligence in maintaining private client or stakeholder data resulted, or could it result, in financial penalties or client attrition to the issuer?	**N**	**N**
	Occupational Health and Safety	Would the failure to address workplace hazards have a negative financial impact on the issuer?	**N**	**N**
	Community Relations	Does engagement, or lack of engagement, with local communities pose a financial or reputational risk to the issuer?	**N**	**N**
	Access to Basic Services	Does a failure to provide or protect with respect to essential products or services have the potential to result in any significant negative financial impact on the issuer?	**N**	**N**
Governance		**Overall:**	**N**	**N**
	Bribery, Corruption, and Political Risks	Do alleged or actual illicit payments pose a financial or reputational risk to the issuer?	**N**	**N**
		Are there any political risks that could impact the issuer's financial position or its reputation?	**N**	**N**
		Bribery, Corruption, and Political Risks	**N**	**N**
	Business Ethics	Do general professional ethics pose a financial or reputational risk to the issuer?	**N**	**N**
	Corporate / Transaction Governance	Does the issuer's corporate structure allow for appropriate board and audit independence?	**N**	**N**
		Have there been significant governance failures that could negatively affect the issuer's financial wellbeing or reputation?	**N**	**N**
		Does the Board and/or management have a formal framework to assess climate-related financial risks to the issuer?	**N**	**N**
		Corporate / Transaction Governance	**N**	**N**
	Institutional Strength, Governance, and Transparency (Governments Only)	Compared with other governments, do institutional arrangements provide a similar degree of accountability, transparency, and effectiveness?	**N**	**N**
		Are regulatory and oversight bodies protected from inappropriate political influence?	**N**	**N**
		Are government officials exposed to public scrutiny and held to high ethical standards of conduct?	**N**	**N**
		Institutional Strength, Governance, and Transparency (Governments Only)	**N**	**N**
		Consolidated ESG Criteria Output:	**N**	**N**

Balance Sheet

(CAD millions)	Dec. 31	Dec. 31	Dec. 31		Dec. 31	Dec. 31	Dec. 31
Assets	**2021**	**2020**	**2019**	**Liabilities & Equity**	**2021**	**2020**	**2019**
Cash & equivalents	868	889	648	Short-term borrowings	193	1,062	178
Accounts receivable	558	492	468	Accounts payable	1,430	1,245	1,095
Inventories	350	328	325	Current portion L.T.D.	179	439	693
Regulatory assets	288	533	486	Regulatory liabilities	276	266	103
Prepaid expenses & other	398	313	320	Deferred revenue & other	0	0	0
Total Current Assets	**2,462**	**2,555**	**2,247**	**Total Current Liabilities**	**2,078**	**3,012**	**2,069**
Net fixed assets	30,327	29,810	26,047	Long-term debt	9,515	8,928	7,574
Intangibles	637	633	471	Deferred income taxes	1,634	1,379	1,154
Financing receivables	0	0	0	Pension & postretirement benefits	6,061	8,411	6,667
Nuclear removal/waste management funds	19,807	19,050	18,252	Nuclear removal/waste management funds	23,415	22,947	22,081
Regulatory assets	6,467	8,571	6,770	Regulatory liabilities	777	1,239	949
Investments & other	1,453	1,454	1,617	Other long-term liabilities	706	625	635
				Shareholders' equity	16,967	15,532	14,275
Total Assets	**61,153**	**62,073**	**55,404**	**Total Liabilities & SE**	**61,153**	**62,073**	**55,404**

Ratios

	For the year ended December 31				
Balance Sheet & Liquidity & Capital Ratios	**2021**	**2020**	**2019**	**2018**	**2017**
Current ratio	1.18	0.85	1.09	1.11	0.79
Total debt in capital structure (%)	36.8	40.2	37.2	37.5	35.6
Total debt in capital structure (%)[1, 2, 3]	30.2	33.8	28.6	26.9	26.2
Cash flow/Total debt (%)	32.2	31.8	30.4	28.0	26.4
Cash flow/Total debt (%)[1, 2]	40.6	39.3	41.7	45.0	40.0
(Cash flow—dividends)/Capex (times)	1.57	1.88	1.25	1.05	0.94
(Cash flow—n.w.f.)/Total debt (%)[1, 2, 5]	37.0	36.3	39.0	39.3	33.7
Dividend payout ratio (%)	0.0	0.0	0.0	103.3	0.0
Coverage Ratios (times)					
EBIT gross interest coverage[4]	2.21	2.73	1.23	0.77	(0.13)
EBIT gross interest coverage[1, 2, 4]	2.43	3.66	0.86	1.00	(0.24)
EBITDA gross interest coverage[4]	5.16	5.91	4.34	3.38	2.17
Fixed-charges coverage[4]	2.21	2.73	1.23	0.77	(0.13)
Profitability Ratios					
EBITDA margin (%)[4]	28.7	34.0	24.8	18.4	12.4
EBIT margin (%)[4]	12.3	15.7	7.0	4.2	-0.7
Profit margin (%)[4]	9.7	9.4	7.8	4.9	-0.3
Return on equity (%)[4]	4.1	4.6	3.4	2.2	-0.1
Return on capital (%)[1, 3, 4]	3.3	3.7	2.5	1.8	0.5

1 Including operating leases.
2 Excludes nonrecourse debt.
3 Adjusted for Accumulated Other Comprehensive Income.
4 Excluding earnings from nuclear fixed asset removal and nuclear waste management funds.
5 Includes nuclear waste funding (n.w.f.) payments as they are not discretionary.

Rating History

	Current	2021	2020	2019	2018	2017
Issuer Rating	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Unsecured Debt	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

Commercial Paper Limit

- $1.0 billion and USD 750 million.

Previous Actions

- "DBRS Morningstar Confirms Ontario Power Generation Inc. at A (low)/R-1 (low), Stable Trends," April 8, 2021.
- "DBRS Morningstar Assigns Rating of A (low) With Stable Trend to Ontario Power Generation Inc.'s $500 Million Series 9 Medium-Term Notes," February 5, 2021.

Previous Report

- Ontario Power Generation Inc.: Rating Report, April 21, 2021.

About DBRS Morningstar

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Rating Report
Ontario Power Generation Inc.

DBRS Morningstar
May 8, 2023

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Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A (low)	Confirmed	Stable
Unsecured Debt	A (low)	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

On April 11, 2023, DBRS Limited (DBRS Morningstar) confirmed the Issuer Rating and Unsecured Debt rating of Ontario Power Generation Inc. (OPG or the Company) at A (low), and the Commercial Paper (CP) rating at R-1 (low). All trends are Stable. The ratings of OPG are based on its regulated generation operations in Ontario. The Stable trend reflects the Company's reasonable key credit metrics, given the complex and substantial capital expenditures (capex) program, for the current ratings.

OPG's business risk assessment has remained steady since the most recent ratings confirmation. There were no material regulatory changes by the Ontario Energy Board (OEB) to the Company's in-service nuclear and hydroelectric power plants. For 2022 to 2026, payment amounts for regulated nuclear operations will increase annually as set under the approved Custom Incentive Rate-setting (IR) framework while base hydroelectric payment amounts remain frozen at 2021 levels. DBRS Morningstar notes that OPG is currently conducting a feasibility study on the refurbishment of four units at the Pickering Nuclear Generating Station (GS) in order to extend its operating life by 30 years, and preparation work to deploy a 300 megawatt (MW) Small Modular Reactor (SMR) at the Darlington site. While these projects would be fully regulated and will substantially increase the Company's rate base when completed, there is significant execution risk because of the complexity and scale of the projects. DBRS Morningstar is encouraged by OPG's current track record with the ongoing Darlington Refurbishment project (total capex of $12.8 billion), which remains on budget and on schedule. DBRS Morningstar will continue to monitor progress on the Darlington Refurbishment and the approval process for the Pickering Refurbishment and SMR project and expects that the Company will not undertake any major capex without having financing and a cost-recovery mechanism in place to minimize financial risks.

OPG's financial risk assessment remains supportive of the current ratings given the substantial capex program ($3.7 billion for 2023). DBRS Morningstar expects the Company's cash flows and key credit metrics to fluctuate moderately over the near term as the Darlington Refurbishment continues, with capacity to vary during this period as units are taken out or placed back in service. DBRS Morningstar

also expects the Company's metrics to remain in line with the current ratings even as debt increases to fund the capex program. A positive rating action is unlikely over the medium term given OPG's business profile and the ongoing significant and complex capex program. A negative rating action is also considered unlikely but may occur should there be cost overruns that result in significant stranded costs for the Company.

Financial Information

	For the year ended December 31				
	2022	**2021**	**2020**	**2019**	**2018**
Cash flow/Total debt (%)[1, 2]	38.9	39.3	39.3	41.7	45.0
Total debt in capital structure (%)[1, 2, 3]	28.4	30.2	33.8	28.6	26.9
EBIT gross interest coverage (times)[1, 2]	6.24	5.90	7.17	4.67	5.72
(Cash flow–n.w.f.)/Total debt (%)[1, 2, 4]	37.2	35.8	36.3	39.0	39.3

1 Including operating leases.
2 Excludes nonrecourse debt.
3 Adjusted for Accumulated Other Comprehensive Income.
4 Includes nuclear waste funding (n.w.f.) payments as they are not discretionary.

Issuer Description

OPG is an electricity generation company with a diverse portfolio of over 18,000 megawatts (MW) of in-service generating capacity. The Company is wholly owned by the Province of Ontario.

Rating Considerations

Strengths

1. Reasonable regulatory framework that provides stable cash flow

The reasonable regulatory framework has allowed the Company to recover prudently incurred costs and provided stable cash flows. DBRS Morningstar notes, however, that there have been disallowances by the OEB in the past on labour compensation costs related to OPG's nuclear operations. DBRS Morningstar also notes that, under an IR framework and the regulated hydroelectric rate freeze, OPG's profitability could come under further pressure because of the need to meet efficiency and productivity benchmarks.

2. Support of shareholder (the Province)

The Province indirectly provides OPG with some of its long-term funding requirements through the Ontario Electricity Financial Corporation (OEFC; rated AA (low) with a Stable trend by DBRS Morningstar), a government financing arm for provincial power companies. DBRS Morningstar believes that the Province will continue to support its investment because OPG is a creation of the Province and is integral to fulfilling Ontario's energy needs. OPG's importance in Ontario is also demonstrated by the fact that it is the primary electricity generator in the province, accounting for approximately 52% of electricity produced in 2022.

DBRS Morningstar notes that OPG's debt is not directly guaranteed by the Province. As at December 31, 2022, OPG had approximately $2.5 billion of notes payable to the OEFC, comprising 25% of the

Company's outstanding debt. While this financial support does not, in itself, result in any uplift to the Company's ratings, the ratings do incorporate DBRS Morningstar's belief that the Province will, in exceptional circumstances, provide support to OPG.

3. Limited nuclear waste management liabilities

As a result of the Ontario Nuclear Funds Agreement with the Province, OPG's exposure to the costs to dispose of the initial 2.23 million used fuel bundles produced has been capped at $21.3 billion (in present value dollars as at December 31, 2022). The used fuel obligation is funded by the used fuel fund, which was fully funded as at December 31, 2022. The Province provides a guarantee for any shortfall between the value of the nuclear fund and the Canadian Nuclear Safety Commission (CNSC) consolidated financial guarantee requirement.

Challenges

1. Significant capex program

OPG has a significant capex program underway (approximately $3.7 billion planned for 2022). The Company also faces significant execution risk as well as the potential for cost overruns associated with the Darlington Refurbishment because of the project's complexity and scale. DBRS Morningstar notes that OPG has started preparation work on its SMR project and a feasibility study on the refurbishment of four units at the Pickering Nuclear GS. These two projects would be complex undertakings and require significant financing. While capex for both these projects will be regulated and should lead to a substantial increase in the rate base, there is considerable execution risk as well that could lead to large cost overruns. DBRS Morningstar is encouraged by OPG's current track record with the Darlington Refurbishment, which remains on budget and on schedule. DBRS Morningstar also expects that the Company will not undertake any major capex without having financing and a cost-recovery mechanism in place, thus minimizing financial risks.

2. Nuclear generation risks

Nuclear generation (approximately 45% of OPG's production in 2022) faces higher operating risks than other types of power generation because of its complex technology. The financial implications of forced outages, especially with older units (e.g., the Pickering Nuclear GS), are greater, given the high fixed-cost nature of these plants and because lost revenues resulting from outages are not recoverable through rates.

3. High cost base

OPG's high cost base has resulted in several disallowances by the OEB. For the 2022–26 rates decision, the Company agreed, in a settlement proposal with intervenors, to reduce its non-Darlington-Refurbishment-related regulated nuclear operations, maintenance, and administration (OM&A) budget by 3% annually (total of $277 million over the five-year term). DBRS Morningstar believes that OPG's inability to fully recover compensation costs in future regulated prices could have a negative impact on earnings and affect the Company's ability to achieve its approved return on equity (ROE). DBRS Morningstar notes that OPG has been combatting this issue through its cost-reduction and efficiency-

improvement initiative, which has previously saved $1.0 billion through a reduction in headcount of over 2,800 since 2011.

4. Political intervention

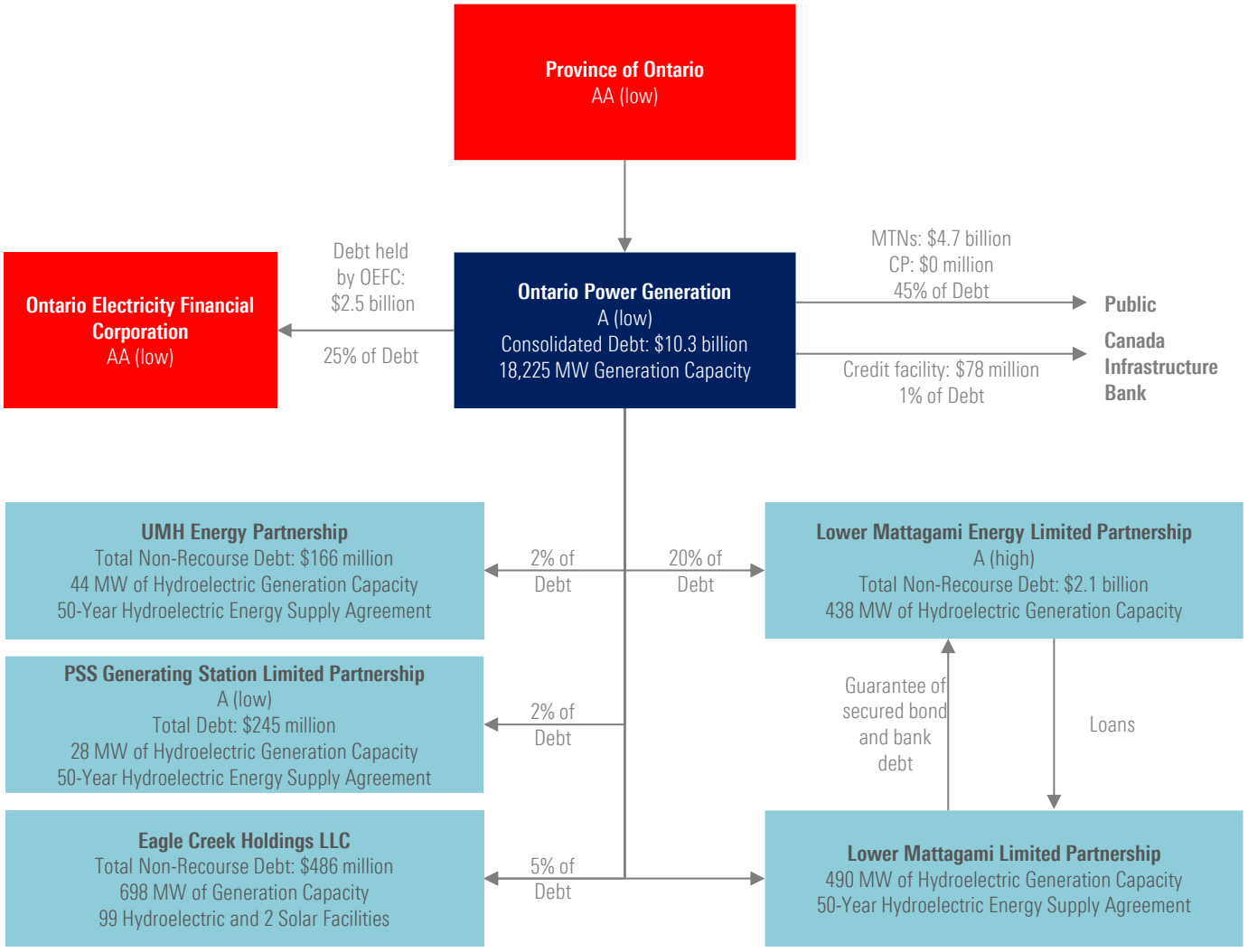
OPG is subject to political intervention, largely because of its ownership by the Province and changes in government mandates and policies. DBRS Morningstar notes that, though the Province has committed to having the Company run more autonomously, the risk of further government intervention still exists. In November 2020, the Province amended legislation to freeze OPG's hydroelectric base rates at the 2021 level for the next regulatory period of 2022–26. DBRS Morningstar expects the Company's earnings to be modestly pressured as OPG will have to find efficiencies to offset inflationary cost increases.

5. Increased exposure to nonregulated operations

OPG has in recent years acquired multiple nonregulated generation assets, including gas-fired plants in Ontario and two renewable facility operators in the U.S. The Company also owns nonregulated natural gas, oil, solar, and biomass generation assets in the province. While the Ontario assets are largely under long-term contracts with strong investment-grade counterparties (such as the Independent Electricity System Operator (IESO)) and contribute relatively stable earnings and cash flow, DBRS Morningstar does view nonregulated assets as generally having higher business risks than the incumbent regulated operations because there is less cost recovery certainty and potentially more volatile cash flow.

DBRS Morningstar notes earnings contributed by regulated operations may fluctuate over the near term resulting in nonregulated earnings to be near or modestly over the 20% threshold as the ongoing Darlington Refurbishment project constricts output. The Company has indicated that growth in its nonregulated business will be at a more moderate pace going forward with most planned capex for its regulated operations. As such, contributions from regulated operations are expected to remain above 80% over the long term, especially once the Darlington Refurbishment is completed in 2026. Additionally, DBRS Morningstar also considers assets under regulatory-styled contracts (such as Lower Mattagami Energy Limited Partnership (LMELP; rated A (high) with a Stable trend by DBRS Morningstar), PSS Generating Station Limited Partnership (PSS; rated A (low) with a Stable trend by DBRS Morningstar), and UMH Energy Partnership (UMH; not rated by DBRS Morningstar)) to have similar credit risks as regulated operations because those contracts mimic the current regulatory construct under the OEB (DBRS Morningstar estimates an EBITDA contribution of 80% from regulated operations and assets under regulatory-styled contracts in 2022). However, should OPG pursue acquisitions that result in a significant shift in the EBITDA mix between regulated and nonregulated operations or lead to credit metrics deteriorating to a level no longer supportive of the current rating category, DBRS Morningstar may take negative rating action.

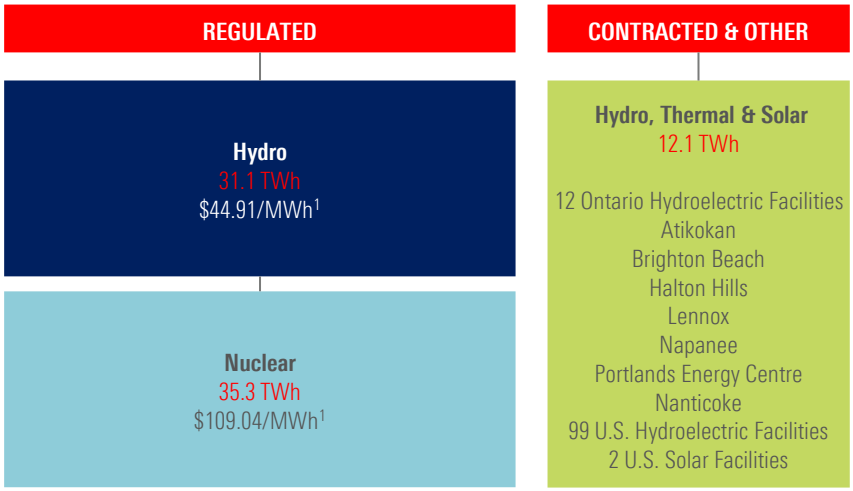
Organizational Chart



As at December 31, 2022.

- As at December 31, 2022, debt at the OPG corporate level consists of $2.6 billion held by the OEFC, and $4.7 billion of medium-term notes (MTNs).
  - Debt at UMH, LMELP, and Eagle Creek Holdings LLC (Eagle Creek) are secured by the assets at each corresponding subsidiary and are nonrecourse to OPG.
  - Debt at PSS GS is recourse to OPG until the recourse release date.

Price Structure



1 Rates as of January 1, 2023.
For the year ended December 31, 2022.
Source: OPG.

- OPG sells electricity to consumers through the IESO.
- Regulated facilities sell at rates set by the OEB, which could include rate riders used for the recovery of nuclear deferral and hydroelectric variance account balances.
- The Contracted and Other Portfolio includes (1) assets in Ontario that sell electricity at prices set through Energy Supply Agreements (ESA) or other long-term contracts with the IESO and (2) Eagle Creek, which holds interest in 99 U.S. hydroelectric GS and two U.S. solar facilities.
  - The Eagle Creek facilities either sell into the merchant market or operate under long-term energy or capacity supply contracts.

Major Projects

Project	Estimated Cost (CAD millions)	Spent as of Dec. 31, 2022 (CAD millions)	In-Service Target Date
Darlington Refurbishment	12,800	9,229	2026[1]
Little Long Dam Safety Project	700	539	2023
Smoky Falls Dam Safety Project	390	117	2025
Calabogie Hydroelectric GS	168	150	2023

1 Four units with staged in-service. Last unit scheduled to be completed by 2026.

- **Darlington Refurbishment**: The Darlington Refurbishment will extend the operating life of the Darlington Nuclear GS by approximately 30 years. The execution of the refurbishment of the first unit began in October 2016, and the last unit is scheduled to be completed by 2026. Construction on the first unit was completed in March 2020 and returned in service in June 2020. Refurbishment on the second unit began in September 2020 after a short delay related to the coronavirus pandemic, and is expected to be placed back in service Q3 2023. Refurbishment on the third unit began in February 2022, with

refurbishment on the final unit expected to begin once the second unit is placed back in service. The project remains on schedule and on budget.

- **Little Long Dam Safety Project**: This project is intended to make reliability and operational improvements and increase the discharge capacity at the Little Long Dam. The Little Long Dam supports hydroelectric GSs on the Lower Mattagami River.
- **Smoky Falls Dam Safety Project**: This project is intended to improve dam safety at the Smoky Falls hydroelectric GS.
- **Calabogie Hydroelectric GS**: This project is intended to redevelop the Calabogie GS by replacing the powerhouse to 11 MW from 5 MW.
- **Pickering Refurbishment**: OPG is in the process of applying to the CNSC to extend the life of the Pickering Nuclear GS to September 2026. The Company is also currently conducting a feasibility study on refurbishing four units of the Pickering Nuclear GS to extend the operating life by 30 years.
- **Darlington New Nuclear Project**: This project involves constructing Canada's first grid-scale SMR at the Darlington site. OPG has applied to the CNSC for a license to construct, with a preliminary schedule of completing construction by 2028 with commercial operation in 2029.

Regulation

- OPG benefits from a reasonably regulated environment. As at December 31, 2022, approximately 63% of its installed in-service capacity is regulated.
- OPG, regulated by the OEB under the *Ontario Energy Board Act, 1998*, is allowed to receive regulated prices for all electricity generated from its nuclear facilities (4,850 MW) as well as most of its hydroelectric power facilities in Ontario (6,555 MW).
- In November 2020, the Province amended *Ontario Regulation (O. Reg.) 53/05* (O. Reg. 53/05) to freeze hydroelectric base rates for OPG at the 2021 level for the next regulatory period of 2022–26.
  - DBRS Morningstar notes the hydroelectric rate freeze may modestly pressure the Company's earnings as OPG will have to find efficiencies in its regulated hydroelectric operations to offset inflationary cost increases.
- In November 2021, the OEB issued its decision on OPG's application for rates effective January 1, 2022.
  - The OEB approved a settlement proposal between OPG and intervenors as filed.
  - As per O. Reg. 53/05, hydroelectric base payment amounts will remain at the 2021 level.
  - Capital structure will remain at 55% debt (the Company had requested a change to 50% debt) and an allowed ROE of 8.66%.
  - For nuclear facilities, the continuation of the current Custom IR methodology along with a rate-smoothing deferral account (as required under O. Reg. 53/05).
  - Under Custom IR, nuclear revenue requirements were determined by a five-year forecast cost-of-service (COS) approach, but with a stretch factor of 0.6% applied to the Company's OM&A expenditures for 2023–25 (compared with 0.45% as requested), and 0.3% for 2026. The reduction in OM&A costs as a result of the stretch factor will accumulate for the five-year period.
  - The rate-smoothing deferral account will stabilize year-to-year changes to weighted-average payment amounts as the Darlington Refurbishment continues. OPG will defer a portion of its approved nuclear revenue requirements into the rate-smoothing deferral account and will be

allowed to recover the deferred amount over a 10-year period once the Darlington Refurbishment has been completed.

- Total regulated nuclear revenue requirement of $16.0 billion over the five-year term, representing a $567 million reduction (including a 3%, or $277 million, reduction of OM&A costs) from the Company's application.
- The OEB approved the inclusion of $8.6 billion to the rate base (including $6.4 billion for the Darlington Refurbishment) over the five-year period of the Custom IR (reduction of $298 million for planned non-Darlington Refurbishment in-service capital add-ons). Any Darlington Refurbishment cost overruns will be subject to a prudence review before being added to the rate base.
- Inclusion of $396 million to the rate base for the Heavy Water Storage and Drum Handling Facility project (in-service 2020); this represents a permanent rate base reduction for the project of $94 million plus carrying costs incurred from May 2017 to March 2020 for capital cost deemed not prudently incurred.
- Recently completed non-Darlington Refurbishment capex of $358 million, which exceeded the 2017–21 approved in-service capital additions, will earn an ROE at the cost of long-term debt (3.6% for the 2022 to 2026 rate period) instead of the allowed ROE until 2037.
- The OEB approved the recovery of balances as at December 31, 2019, in OPG's deferral and variance accounts. The OEB also approved a $47 million credit to customers for the impact of favourable electricity revenue during the 2020 and 2021 Coronavirus (COVID-19) Disease pandemic response (net of any incremental pandemic-related OM&A).
- All previously existing regulatory accounts will continue, along with new accounts to track (1) any financial impact from a possible transition to and implementation of IFRS from US GAAP, (2) revenue requirement impact for a planned new corporate campus, and (3) any revenue requirement impact to nuclear liabilities and depreciation expense from accounting end-of-life assumptions for the Pickering GS.
- An earnings-sharing mechanism was also approved, where regulated earnings 100 basis points above the approved ROE over the cumulative five-year term will be shared 50-50 with customers.

Approved Regulated Nuclear Amounts	2022	2023	2024	2025	2026
Nuclear revenue requirement (CAD millions)	3,515.5	3,430.0	3,518.3	3,197.6	2,439.5
Nuclear rate base (CAD millions)	8,600.3	8,615.0	11,033.4	12,188.8	12,991.8
Nuclear payment amount (CAD per megawatt hour (MWh))	105.22	109.04	104.63	108.19	118.91
Hydro payment amount (CAD per MWh)	44.91	44.91	44.91	44.57	44.57

- In September 2022, the Province announced it will support extending Pickering GS to September 2026 (subject to CNSC approval), and for OPG to conduct a feasibility study on the refurbishment of four units.
  - In December 2022, the Province amended O. Reg. 53/05 to require OPG to establish a variance account to track the additional revenues and costs associated with operating Units 5 to 8 of the Pickering GS between January 1 and September 30, 2026. The disposition of the account balance will be subject to the OEB's prudence review and approval in a future proceeding.
- Effective January 1, 2022, O. Reg. 53/05 was amended so that any SMR constructed at the Darlington site will be considered a regulated facility prescribed under OEB regulation.

Assessment of Regulatory Framework

Criteria	Score	Analysis
1. Deemed Equity	Excellent	The OEB allows OPG to have a deemed equity of 45%.
	Good	
	Satisfactory	
	Below Average	
	Poor	
2. Allowed ROE	Excellent	OPG has an allowed ROE of 8.66% for 2022–26 (based on nuclear regulated rates), which is in line with the other regulated utilities in Ontario. Any difference in ROE between the Company and other regulated utilities in the province is mainly because of the timing of the regulatory filings and the interest environment prevalent at that time.
	Good	
	Satisfactory	
	Below Average	
	Poor	
3. Energy Cost Recovery	Excellent	N/A; energy costs are recovered through rates for OPG.
	Good	
	Satisfactory	
	Below Average	
	Poor	
4. Capital and Operating Cost Recovery	Excellent	Under Custom IR for the nuclear facilities, the capex program for OPG is preapproved for a five-year period by the OEB and recovered through base rates. Future test years are utilized for nuclear rates applications. Some volume risk exists, but this is partly mitigated by (1) use of deferral accounts for volumetric differences, and (2) rates are based on forecasts which include scheduled outages. However, lost revenues resulting from forced outages beyond the forecasted allowances are not recoverable through rates.
	Good	
	Satisfactory	
	Below Average	
	Poor	
5. COS versus IRM	Excellent	The nuclear facilities operate under Custom IR, which is a hybrid of COS and the IR framework, for a five-year term. DBRS Morningstar considers the Custom IR framework as reasonable.
	Good	
	Satisfactory	
	Below Average	
	Poor	
6. Political Interference	Excellent	The Government of Ontario plays a significant role in the electricity sector in Ontario, given that most of the utilities are government owned (OPG is owned by the Province). Furthermore, stakeholders, such as the IESO, are also government owned. As a result, the government has direct and indirect influence on Ontario's electricity industry.
	Good	
	Satisfactory	
	Below Average	
	Poor	
7. Stranded Cost Recovery	Excellent	Regulated utilities in Ontario have a limited history of stranded costs. Most prudently incurred or budgeted capex is approved by the OEB. While OPG has seen some write-downs, these have been because the OEB had deemed the costs overruns to have been imprudent.
	Good	
	Satisfactory	
	Below Average	
	Poor	
8. Rate Freeze	Excellent	DBRS Morningstar notes that, in November 2020, the Province amended O. Reg. 53/05 to freeze hydroelectric base rates for the Company at the 2021 level for the next regulatory period from 2022 to 2026. Rates for nuclear facilities were not frozen and have been set by the OEB. DBRS Morningstar notes that the hydroelectric rate freeze may modestly pressure OPG's earnings as the Company will have to find efficiencies to offset inflation.
	Good	
	Satisfactory	
	Below Average	
	Poor	

Earnings and Outlook

	For the year ended December 31				
(CAD millions where applicable)	**2022**	**2021**	**2020**	**2019**	**2018**
Revenues	7,349	6,877	7,240	6,022	5,535
EBITDA	3,161	2,944	3,387	2,390	1,871
EBIT	2,037	1,812	2,065	1,317	1,087
Gross interest expense	381	383	416	345	301
Earning before taxes	1,851	1,592	1,763	1,333	1,079
Net income before nonrecurring items	1,531	1,355	1,361	1,126	902
Reported net income	1,636	1,325	1,361	1,126	1,195
Return on equity (%)	8.5	8.3	9.1	8.2	7.2
Segmented reported EBITDA					
Nuclear generation	1,425	1,210	1,917	1,306	863
Nuclear sustainability services	(93)	(110)	(113)	(113)	(117)
Regulated hydroelectric generation	854	898	874	843	748
Contracted and other generation	444	369	348	341	384
Atura Power	417	387	279	57	0
Reported subtotal	**3,047**	**2,754**	**3,305**	**2,434**	**1,878**
Other	247	194	87	36	337
Reported total	**3,294**	**2,948**	**3,392**	**2,470**	**2,215**
Nuclear rate base	8,600	7,711	7,347	3,374	3,446
Approved regulated ROE (%)	8.66	8.78	8.78	8.78	8.78
Achieved regulated ROE (%)	N/A	10.79	17.22	15.72	10.72

2022 Summary

- DBRS Morningstar no longer excludes earnings from nuclear fixed asset removal and nuclear waste management funds. The financials above have been restated by DBRS Morningstar.
- EBITDA and EBIT increased primarily because of higher nuclear base rates effective January 1, 2022.
  - Earnings also benefitted from higher wholesale electricity prices from US operations.
  - The increase was offset by lower nuclear generation for the year because of the ongoing Darlington Refurbishment and higher deprecation from the growing rate base.
- Reported net income included a $129 million gain on sale of the Kipling office and facility.

2023 Outlook

- DBRS Morningstar expects OPG's net income in 2023 to increase modestly, reflecting continued growth in the rate base.
  - Earnings from regulated nuclear generation are expected to be steady with both Units 1 and Units 3 of the Darlington Nuclear GS out for refurbishment. DBRS Morningstar does not expect refurbishment on Unit 4 to begin until Unit 3 is back in service.
  - Earnings from regulated hydroelectric generation should remain stable despite the rate freeze.
  - OPG also expects earnings from contracted generation assets and Atura Power to be stable.

- Earnings volatility going forward will come from (1) forecast risk as part of the IR process, (2) macro factors such as weather, unexpected outages, and Ontario's economic conditions, and (3) variability in water flows and wholesale electricity prices for uncontracted facilities.

Financial Profile

	For the year ended December 31				
(CAD millions where applicable)	**2022**	**2021**	**2020**	**2019**	**2018**
Net income before nonrecurring items	1,531	1,355	1,361	1,126	902
Depreciation & amortization	1,124	1,132	1,322	1,073	784
Deferred income taxes and other	560	603	633	369	519
Cash flow (before working capital changes)	**3,215**	**3,090**	**3,316**	**2,568**	**2,205**
Nuclear waste funding	(417)	(458)	(439)	(336)	(307)
Dividends paid	0	0	0	0	(283)
Capital expenditures	(2,557)	(2,025)	(1,765)	(2,058)	(1,826)
Free cash flow (before working capital changes)	**241**	**607**	**1,112**	**174**	**(211)**
Changes in noncash working cap. Items	223	59	103	99	(160)
Change in regulatory assets/liabilities	(24)	(251)	(156)	275	(51)
Net free cash flow	**440**	**415**	**1,059**	**548**	**(422)**
Long-term investments	(31)	(112)	(2,814)	(1,232)	(358)
Proceeds on asset sales	162	0	0	11	289
Acquisition of Fair Hydro Trust receivables	0	0	0	0	(609)
Change in Fair Hydro Trust debt	0	0	0	0	306
Net equity change	0	0	0	0	268
Net debt change	339	(527)	1,993	866	622
Other	(13)	197	(11)	(8)	(17)
Change in cash	**897**	**(27)**	**227**	**185**	**79**
Total debt[2]	7,528	7,353	7,928	5,729	4,730
Cash flow/Total debt (%)[1, 2]	38.9	39.3	39.3	41.7	45.0
Total debt in capital structure (%)[1, 2, 3]	28.4	30.2	33.8	28.6	26.9
EBIT gross interest coverage (times)[1, 2]	6.24	5.90	7.17	4.67	5.72
(Cash flow—n.w.f.)/Total debt (%)[1, 2, 4]	37.2	35.8	36.3	39.0	39.3

1 Including operating leases.
2 Excludes nonrecourse debt.
3 Adjusted for Accumulated Other Comprehensive Income.
4 Includes nuclear waste funding (n.w.f.) payments as they are not discretionary.

2022 Summary

- OPG's key credit metrics exclude nonrecourse debt from UMH, LMELP, and Eagle Creek.
  - The Company's key credit metrics were all stable for the year and remained supportive of the current ratings.
- Cash flow from operations increased tracking the higher net income.
- Capex increased to $2.6 billion because of continued spending for the Darlington Refurbishment, preparation work on the SMR project, and advancement on the Niagara Hydrogen Centre.

- Proceeds on asset sales represents proceeds from sale of the Kipling office and facility.

2023 Outlook

- DBRS Morningstar expects OPG's key credit metrics to remain supportive of the current ratings in 2023.
  - Cash flow from operations is expected to decrease in 2023 because of the timing of the collection of customer receipts.
- OPG has forecast capex to increase substantially to $3.7 billion for 2023 largely because of work on both Units 1, 3 and 4 of the Darlington Refurbishment, work on the Little Long Dam Safety project, and continued preparation work on the SMR project.

Long-term Debt and Credit Facilities

Long-term Debt

(CAD millions)	Maturity	Dec 31, 2022	Dec. 31, 2021
Notes payable to the OEFC	2023–48	2,540	2,690
Medium Term Note Program	2025–51	4,650	4,350
Canada Infrastructure Bank credit facility	2042	78	0
UMH Energy Partnership[1]	2041	166	169
PSS Generating Station Limited Partnership[2]	2067	245	245
Lower Mattagami Energy Limited Partnership[1]	2024–52	1,995	1,745
Eagle Creek[1]	2025–30	486	471
Other		25	25
Subtotal		**10,185**	**9,695**
Less: Fair value discount		7	10
Less: Bond issuance fees		(40)	(39)
Less: Current portion		(43)	(179)
Total long-term debt		**10,109**	**9,487**

1 Nonrecourse to OPG as debt is secured by assets of the associated project.
2 Secured by assets of the project; recourse to OPG until the recourse release date.

- On July 14, 2022, OPG issued $300 million of green bonds under its Medium Term Note Program maturing in July 2032, with a coupon rate of 4.92%.
- The amortizing UMH notes were issued in 2009 with a maturity date of 2041 and an effective interest rate of 7.86%. The notes are secured by the assets of the Upper Mattagami and Hound Chute project and are nonrecourse to OPG.
- The amortizing PSS GS notes were issued in 2015 with a maturity date of 2067 and an effective interest rate of 4.90%. The notes are secured by the assets of PSS GS and are recourse to OPG until the recourse release date (expected in 2023).
- The LMELP notes are secured by the assets of the project and are nonrecourse to OPG.
  - In October 2022, LMELP issued $250 million of Senior Secured Bonds maturing in 2033 at a coupon rate of 4.85%.
- $486 million of long-term debt at year end 2022 related to Eagle Creek. The notes are secured by the assets of Eagle Creek and are nonrecourse to the Company.

Maturity Profile							
(CAD millions—as at December 31, 2022)	**2023**	**2024**	**2025**	**2026**	**2027**	**Thereafter**	**Total**
Long-Term Debt	43	606	589	674	530	7,743	**10,185**
	0%	6%	6%	7%	5%	76%	**100%**

- OPG's maturity profile is fairly spread out.

Credit Facilities				
(CAD millions—as at December 31, 2022)	**Maturity**	**Amount**	**Drawn/LOC**	**Available**
Committed credit facility	May 2027	1,000	0	**1,000**
Committed credit facility—USD 750 million	Nov. 2023	1,016	0	1,016
OEFC general corporate credit facility	Dec. 2026	750	0	750
Canada Infrastructure Bank credit facility	Sep. 2027[2]	970	78	892
Short-term uncommitted credit facilities	Demand	502	363	139
Short-term uncommitted overdraft facilities	Demand	25	0	25
Lower Mattagami River Project[1]	Aug. 2027	400	60	340
UMH Energy Partnership credit facilities[1]	Oct. 2023	16	16	0
UMH Energy Partnership overdraft facilities[1]	Oct. 2023	8	0	8
Eagle Creek credit facility—USD 5 million[1]	Aug. 2023	7	0	7
Eagle Creek credit facility—USD 20 million[1]	Oct. 2028	27	0	27
Subtotal		**4,721**	**517**	**4,204**
CPs issued—Corporate			0	0
CPs issued—LMELP			65	(65)
Total		**4,721**	**582**	**4,139**

1 Nonrecourse to OPG as debt is secured by assets of the associated project.
2 The availability period to borrow under the facility is expected to end by September 2027, and amounts drawn under the facility have an expected maturity date of September 2042, subject to certain conditions.

- OPG has a reasonable liquidity profile.
- The Company has a $1.0 billion Canadian CP program (none outstanding as at December 31, 2022) and a USD 750 million CP program in the U.S. (none outstanding as at December 31, 2022; unrated by DBRS Morningstar). These CP programs are supported by the following facilities:
  - Committed bank facility of $1.0 billion (due date of May 2027);
  - A USD 750 million bank facility (due date of November 2023, with a one-year term-out option); and
  - An OEFC facility of $750 million (due date of December 2026).
- In August 2022, OPG entered into a $970 million non-revolving term credit facility with the Canada Infrastructure Bank. The facility will be available to borrow on until September 2027, with any outstanding amounts to have an extended maturity date of September 2042, subject to certain conditions.
- As at December 31, 2022, OPG had issued $439 million in letters of credit (LOC) under its corporate facilities of which $298 million was attributed to its supplementary pension plan.
- The LMELP, UMH, and Eagle Creek facilities are used to support the respective projects and are nonrecourse to OPG.

Company Profile

Generation Profile

As at December 31, 2022	Percent (%)	Capacity (MW)
Nuclear		
Darlington	10	1,756
Pickering A	6	1,030
Pickering B	11	2,064
	27	**4,850**
Thermal		
Atikokan (Biomass)	1	205
Brighton Beach	3	570
Halton Hills	4	683
Napanee	5	900
Portlands Energy Centre	3	562
Lennox (Dual oil & gas)	12	2,100
	28	**5,020**
Hydroelectric		
Nonregulated[1]	9	1,726
Regulated	36	6,555
	45	**8,281**
Other		
Solar[2]	0	74
Total Capacity	**100**	**18,225**

1 Represents OPG's share of in-service generation.
2 Three solar facilities.

- OPG is the largest generator of electricity in Ontario.
- In 2022, the Company generated 78.5 terawatt hours of electricity with total in-service capacity of 18,225 MW as at December 31, 2022.
  - The decrease can largely be attributed to two units of the Darlington GS taken out for refurbishment.
- OPG partnerships consist of the following:
  - OPG and the Lac Seul First Nation (LSFN) jointly own the Lac Seul GS, with LSFN owning 25% of the facility.
  - OPG and the Moose Cree First Nation (MCFN), through its wholly owned subsidiary, Amisk-oo-Skow Finance Corporation, jointly own the Little Long, Harmon, Kipling, and Smoky Falls GS, with MCFN owning 25% of the facilities.
  - OPG and Coral Rapids Power Corporation (CRP), a wholly owned subsidiary of the Taykwa Tagamou Nation, jointly own PSS GS, with CRP owning 33% of the facility.
  - OPG, a subsidiary of the Six Nations of the Grand River Development Corporation, and a subsidiary of Mississaugas of the Credit First Nation jointly own the Nanticoke Solar Facility, with OPG owning 80% of the facility.

- OPG also owns the Bruce A and Bruce B Nuclear GS, which are leased on a long-term basis to Bruce Power L.P. (rated BBB with a Stable trend by DBRS Morningstar).

Environmental, Social, and Governance (ESG) Credit Risk Considerations

Environmental

There were no environmental factors that had a relevant or significant effect on the credit analysis. For more details about which environmental factors could have an effect on the credit analysis, please refer to the following checklist. DBRS Morningstar notes OPG operates the Darlington and Pickering Nuclear GSs, which creates nuclear by-products such as used fuel, and low-level and intermediate-level materials. OPG's nuclear operations and handling of nuclear by-products are regulated by the CNSC. The Company also has nuclear fixed asset removal and nuclear waste management funds for costs to be incurred for the safe storage of nuclear materials, and for the eventual dismantlement of the facilities and remediation of the land. As at December 31, 2022, the Decommissioning Segregated Fund was overfunded by 31%, and the Used Fuel Segregated Fund was overfunded by 5%. DBRS Morningstar expects costs associated with OPG's handling of nuclear by-products to be funded through regulated rates.

Social

There were no social factors that had a relevant or significant effect on the credit analysis. For more details about which social factors could have an effect on the credit analysis, please refer to the following checklist.

Governance

There were no governance factors that had a relevant or significant effect on the credit analysis. For more details about which governance factors could have an effect on the credit analysis, please refer to the following checklist.

A description of how DBRS Morningstar considers ESG factors within the DBRS Morningstar analytical framework can be found in *DBRS Morningstar Criteria: Approach to Environmental, Social, and Governance Risk Factors in Credit Ratings* at https://www.dbrsmorningstar.com/research/396929/dbrs-morningstar-criteria-approach-to-environmental-social-and-governance-risk-factors-in-credit-ratings.

ESG Factor		ESG Credit Consideration Applicable to the Credit Analysis: Y/N		Extent of the Effect on the ESG Factor on the Credit Analysis: Relevant (R) or Significant (S)*
Environmental		**Overall:**	**N**	**N**
	Emissions,Effluents, and Waste	Do we consider the costs or risks result, or could result in changes to an issuer's financial, operational, and/or reputational standing?	**N**	**N**
	Carbon and GHG Costs	Does the issuer face increased regulatory pressure relating to the carbon impact of its or its clients' operations resulting in additional costs?	**N**	**N**
	Resource and Energy Management	Does the scarcity of sourcing key resources hinder the production or operations of the issuer, resulting in lower productivity and therefore revenues?	**N**	**N**
	Land Impact and Biodiversity	Is there a financial risk to the issuer for failing to effectively manage land conversion, rehabilitation, land impact, or biodiversity activities?	**N**	**N**
	Climate and Weather Risks	Will climate change and adverse weather events potentially disrupt issuer or client operations, causing a negative financial impact?	**N**	**N**
Social		**Overall:**	**N**	**N**
	Social Impact of Products and Services	Do we consider that the social impact of the issuer's products and services could pose a financial or regulatory risk to the issuer?	**N**	**N**
	Human Capital and Human Rights	Is the issuer exposed to staffing risks, such as the scarcity of skilled labour, uncompetitive wages, or frequent labour relations conflicts that could result in a material financial or operational impact?	**N**	**N**
		Do violations of rights create a potential liability that can negatively affect the issue's financial wellbeing or reputation?	**N**	**N**
		Human Capital and Human Rights:	**N**	**N**
	Product Governance	Does failure in delivering quality products and services cause damage to customers and expose the issuer to financial and legal liability?	**N**	**N**
	Data Privacy and Security	Has misuse or negligence in maintaining private client or stakeholder data resulted, or could result, in financial penalties or client attrition to the issuer?	**N**	**N**
	Occupational Health and Safety	Would the failure to address workplace hazards have a negative financial impact on the issuer?	**N**	**N**
	Community Relations	Does engagement, or lack of engagement, with local communities pose a financial or reputational risk to the issuer?	**N**	**N**
	Access to Basic Services	Does a failure to provide or protect with respect to essential products or services have the potential to result in any significant negative financial impact on the issuer?	**N**	**N**
Governance		**Overall:**	**N**	**N**
	Bribery, Corruption, and Political Risks	Do alleged or actual illicit payments pose a financial or reputational risk to the issuer?	**N**	**N**
		Are there any political risks that could impact the issuer's financial position or its reputation?	**N**	**N**
		Bribery, Corruption, and Political Risks:	**N**	**N**
	Business Ethics	Do general professional ethics pose a financial or reputational risk to the issuer?	**N**	**N**
	Corporate / Transaction Governance	Does the issuer's corporate structure limit appropriate board and audit independence?	**N**	**N**
		Have there been significant governance failures that could negatively affect the issuer's financial wellbeing or reputation?	**N**	**N**
		Corporate / Transaction Governance:	**N**	**N**
	Institutional Strength, Governance, and Transparency (Governments Only)s	Compared with other governments, do institutional arrangements provide a higher or lesser degree of accountability, transparency, and effectiveness?	**N**	**N**
		Are regulatory and oversight bodies insufficiently protected from inappropriate political influence?	**N**	**N**
		Are government officials insufficiently exposed to public scrutiny or held to insufficiently high ethical standards of conduct?	**N**	**N**
		Institutional Strength, Governance, and Transparency (Governments Only)s:	**N**	**N**
		Consolidated ESG Criteria Output:	**N**	**N**

Balance Sheet

(CAD millions)	Dec 31	Dec. 31	Dec. 31		Dec 31	Dec. 31	Dec. 31
Assets	**2022**	**2021**	**2020**	**Liabilities & Equity**	**2022**	**2021**	**2020**
Cash & equivalents	1,753	868	889	Short-term borrowings	76	193	1,062
Accounts receivable	484	558	492	Accounts payable	1,761	1,430	1,245
Inventories	358	350	328	Current portion L.T.D.	43	179	439
Regulatory assets	227	288	533	Regulatory liabilities	215	276	266
Prepaid expenses & other	730	398	313	Deferred revenue & other	0	0	0
Total Current Assets	**3,552**	**2,462**	**2,555**	**Total Current Liabilities**	**2,095**	**2,078**	**3,012**
Net fixed assets	31,767	30,327	29,810	Long-term debt	10,145	9,515	8,928
Intangibles	666	637	633	Deferred income taxes	1,897	1,634	1,379
Financing receivables	0	0	0	Pension & postretirement benefits	2,322	6,061	8,411
Nuclear removal/waste management funds	20,655	19,807	19,050	Nuclear removal/waste management funds	24,315	23,415	22,947
Regulatory assets	3,797	6,467	8,571	Regulatory liabilities	1,859	777	1,239
Investments & other	1,906	1,453	1,454	Other long-term liabilities	721	706	625
				Shareholders' equity	18,989	16,967	15,532
Total Assets	**62,343**	**61,153**	**62,073**	**Total Liabilities & SE**	**62,343**	**61,153**	**62,073**

Ratios

	For the year ended December 31				
Balance Sheet & Liquidity & Capital Ratios	**2022**	**2021**	**2020**	**2019**	**2018**
Current ratio	1.70	1.18	0.85	1.09	1.11
Total debt in capital structure (%)	35.1	36.8	40.2	37.2	37.5
Total debt in capital structure (%)[1, 2, 3]	28.4	30.2	33.8	28.6	26.9
Cash flow/Total debt (%)	31.3	31.3	31.8	30.4	28.0
Cash flow/Total debt (%)[1, 2]	38.9	39.3	39.3	41.7	45.0
(Cash flow—dividends)/Capex (times)	1.26	1.53	1.88	1.25	1.05
(Cash flow—n.w.f.)/Total debt (%)[1, 2, 4]	37.2	35.8	36.3	39.0	39.3
Dividend payout ratio (%)	0.0	0.0	0.0	0.0	31.4
Coverage Ratios (times)					
EBIT gross interest coverage	5.35	4.73	4.96	3.82	3.61
EBIT gross interest coverage[1, 2]	6.24	5.90	7.17	4.67	5.72
EBITDA gross interest coverage	8.30	7.69	8.14	6.93	6.22
Fixed-charges coverage	5.35	4.73	4.96	3.82	3.61
Profitability Ratios					
EBITDA margin (%)	43.0	42.8	46.8	39.7	33.8
EBIT margin (%)	27.7	26.3	28.5	21.9	19.6
Profit margin (%)	20.8	19.7	18.8	18.7	16.3
Return on equity (%)	8.5	8.3	9.1	8.2	7.2
Return on capital (%)[1, 3]	6.1	5.9	6.4	5.5	4.9

1 Including operating leases.
2 Excludes nonrecourse debt.
3 Adjusted for Accumulated Other Comprehensive Income.
4 Includes nuclear waste funding (n.w.f.) payments as they are not discretionary.

Rating History

	Current	2022	2021	2020	2019	2018
Issuer Rating	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Unsecured Debt	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

Commercial Paper Limit

- $1.0 billion and USD 750 million.

Previous Actions

- "DBRS Morningstar Assigns Rating of A (low) With Stable Trend to Ontario Power Generation Inc.'s $300 Million Series 10 Medium-Term Notes," July 20, 2022.
- "DBRS Morningstar Confirms Ontario Power Generation Inc. at A (low)/R-1 (low), Stable Trends," April 8, 2022.

Previous Report

- Ontario Power Generation Inc.: Rating Report, April 25, 2022.

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MORNINGSTAR DBRS

Rating Report
Ontario Power Generation Inc.

Morningstar DBRS
April 30, 2024

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Commercial Paper Limit
$1.0 billion and USD 750 million

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Credit Ratings

Obligation	Rating	Rating Action	Trend
Issuer Rating	A (low)	Confirmed	Stable
Unsecured Debt	A (low)	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Credit Ratings Drivers

Positive Credit Rating Drivers	Negative Credit Rating Drivers
DBRS Limited (Morningstar DBRS) believes a positive rating action is unlikely over the medium term given the business profile and the ongoing significant and complex capital expenditures (capex) program.	A negative rating action is also considered unlikely given the reasonable key credit metrics, but may occur should there be cost overruns that result in significant stranded costs.

Key Credit Rating Considerations

The ratings on Ontario Power Generation Inc. (OPG or the Company) are based on its regulated generation business, which operates under a reasonable regulatory regime under the Ontario Energy Board (OEB). The Stable trends reflect the Company's key credit metrics, which remain reasonable given the complex and substantial capex program.

Morningstar DBRS notes OPG has a number of large capital projects ongoing. Work has continued on the Darlington Refurbishment project (total capex of $12.8 billion). OPG continues to assess and seek ways to manage the impact of the COVID-19 pandemic on the project's total cost, which otherwise remains on budget and on schedule. In July 2023, the Province of Ontario (the Province or Ontario; 100% owner of OPG; rated AA (low) with a Positive trend by Morningstar DBRS) announced that the Company will begin planning and licensing three additional Small Modular Reactors (SMRs) at Darlington. Public hearings with the Canadian Nuclear Safety Commission (CNSC) on the first SMR at Darlington began in January 2024. In April 2024, the CNSC announced that the existing environmental assessment at Darlington is applicable for the selected SMR technology, which is a positive step forward for the project. As well, in January 2024, the Province announced its support for OPG proceeding with certain pre-executive phase activities, which include preliminary engineering work and securing long-lead components, with a budget of approximately $2 billion, for the refurbishment of Units 5-8 of the Pickering Nuclear Generating Station (GS), which is anticipated to be returned to service by the mid-2030s. Additionally, wholly-owned subsidiary Atura Power, as part of OPG's nonregulated segment, is constructing a large-scale hydrogen production facility and a 250-megawatt (MW) battery energy storage system (BESS). With the electrification of the economy and the expected increase in electricity demand in the Province, the Company also intends to pursue opportunities to increase generation

capacity such as through Independent Electricity System Operator (IESO) request for proposals or the development of hydro sites throughout the Province.

Financial Outlook

Given these ongoing projects, OPG has forecast capex to almost double in 2024 from $2.9 billion in 2023. Morningstar DBRS expects capex to remain at this level for at least the near term, and will likely result in substantial net free cash flow deficits that will require debt financing. Morningstar DBRS notes that the Company is exploring additional funding sources, such as investment tax credits or partnerships with government and Indigenous communities which would reduce its debt needs. While most of OPG's projects are regulated and will be added to the Company's rate base when completed, there is significant execution risk because of the complexity and scale of the projects. Morningstar DBRS has factored into OPG's current ratings that its key credit metrics will weaken moderately over the medium-term, but, given the complexity of the projects, remain reasonable for the A (low) rating. Morningstar DBRS will continue to monitor progress on the Darlington Refurbishment, the Pickering Refurbishment, and the SMR project, and expects that the Company will not undertake any major capex without having financing and a cost-recovery mechanism in place to minimize financial risks.

Earnings Outlook

OPG expects earnings in 2024 to be lower than in 2023 because of higher planned outage days for maintenance for the Darlington GS, the planned shutdown of Unit 1 of the Pickering GS in September 2024, and lower regulated nuclear prices for the year. Overall, Morningstar DBRS expects earnings volatility going forward will come from (1) forecast risk as part of the regulatory process; (2) macro factors such as weather, unexpected outages, and Ontario's economic conditions; and (3) variability in water flows and wholesale electricity prices for uncontracted facilities.

Financial Information

	For the year ended December 31				
	2023	**2022**	**2021**	**2020**	**2019**
Cash flow/total debt (%)	31.3	31.3	31.3	31.8	30.4
Total debt in capital structure (%)[1]	34.0	35.2	36.5	39.6	36.7
EBIT gross interest coverage (times)	5.37	5.35	4.73	5.00	3.97

1 Adjusted for Accumulated Other Comprehensive Income.
Note: Morningstar DBRS no longer excludes nonrecourse debt in its calculation of key metrics.

Issuer Description

OPG is an electricity generation company with a diverse portfolio of more than 18,000 MW of in-service generating capacity. The Company is wholly owned by the Province.

Business Risk Assessment

1. Reasonable regulatory framework that provides stable cash flow

The reasonable regulatory framework has allowed OPG to recover prudently incurred costs and provided stable cash flows. Morningstar DBRS notes; however, that there have been disallowances by the OEB in the past on labour compensation costs related to the Company's nuclear operations. Morningstar DBRS also notes that, under an incentive rate-setting (IR) framework and the regulated hydroelectric rate

freeze, OPG's profitability could come under further pressure because of the need to meet efficiency and productivity benchmarks.

2. Support of shareholder (the Province)

The Province indirectly provides OPG with some of its long-term funding requirements through the Ontario Electricity Financial Corporation (OEFC; rated AA (low) with a Positive trend by Morningstar DBRS), a government financing arm for provincial power companies. As at December 31, 2023, OPG had approximately $2.5 billion of notes payable to the OEFC, comprising 24% of the Company's outstanding debt. Morningstar DBRS believes that the Province will continue to support its investment because OPG is a creation of the Province and is integral to fulfilling Ontario's energy needs. OPG's importance in Ontario is also demonstrated by the fact that it is the primary electricity generator in Ontario, accounting for approximately 54% of electricity produced in 2023. While OPG's debt is not directly guaranteed by the Province, Morningstar DBRS believes that the Province will, in exceptional circumstances, provide support to the Company.

3. Nuclear generation risks

Nuclear generation (approximately 45% of OPG's production in 2023) faces higher operating risks than other types of power generation because of its complex technology. The financial implications of forced outages are greater, given the high fixed-cost nature of these plants and because lost revenues resulting from outages are not recoverable through rates.

4. Political intervention

OPG is subject to political intervention, largely because of its ownership by the Province and changes in government mandates and policies. Morningstar DBRS notes that, though the Province has committed to having the Company run more autonomously, the risk of further government intervention still exists. In November 2020, the Province amended legislation to freeze OPG's hydroelectric base rates at the 2021 level for the next regulatory period of 2022–26. Morningstar DBRS expects the Company's earnings to be modestly pressured as OPG will have to find efficiencies to offset inflationary cost increases.

5. Exposure to nonregulated operations

OPG owns several nonregulated generation assets, including gas-fired plants in Ontario and a renewable facility operator and developer in the U.S. The Company also owns nonregulated natural gas, oil, solar, and biomass generation assets in the province. While the Ontario assets are largely under long-term contracts with strong investment-grade counterparties (such as the IESO) and contribute relatively stable earnings and cash flow, Morningstar DBRS does view nonregulated assets as generally having higher business risks than the incumbent regulated operations because there is less cost recovery certainty and potentially more volatile cash flow.

Morningstar DBRS notes earnings contributed by regulated operations may fluctuate over the near term resulting in nonregulated earnings to be near or modestly more than the 20% threshold as the ongoing Darlington Refurbishment project and the expected Pickering Refurbishment constricts output. The Company has indicated that growth in its nonregulated business will be at a more moderate pace going

forward with most planned capex for its regulated operations. As such, contributions from regulated operations are expected to remain higher than 80% over the long term, especially once the Darlington Refurbishment is completed in 2026. Additionally, Morningstar DBRS also considers assets under regulatory-styled contracts (such as Lower Mattagami Energy Limited Partnership (LMELP; rated A (high) with a Stable trend by Morningstar DBRS), PSS Generating Station LP (New Post Creek) (PSS; rated A (low) with a Stable trend by Morningstar DBRS), and UMH Energy Partnership (UMH) to have similar credit risks as regulated operations because those contracts mimic the current regulatory construct under the OEB (Morningstar DBRS estimates an EBITDA contribution of 84% from regulated operations and assets under regulatory-styled contracts in 2023). However, should OPG pursue acquisitions that result in a significant shift in the EBITDA mix between regulated and nonregulated operations or lead to credit metrics deteriorating to a level no longer supportive of the current rating category, Morningstar DBRS may take negative rating action.

Financial Risk Assessment

1. Significant capex program

OPG has a significant capex program under way (approximately $5.7 billion planned for 2024). The Company also faces significant execution risk as well as the potential for cost overruns associated with the Darlington Refurbishment because of the project's complexity and scale. Morningstar DBRS notes that OPG has started preparation work on its SMR project and initial preparation work to refurbish four units at the Pickering GS. These two projects would be complex undertakings and require significant financing. While capex for both these projects will be regulated and should lead to a substantial increase in the rate base, there is considerable execution risk as well that could lead to large cost overruns. Morningstar DBRS is encouraged by OPG's current track record with the Darlington Refurbishment, which remains on budget and on schedule. Morningstar DBRS also expects that the Company will not undertake any major capex without having financing and a cost-recovery mechanism in place, thus minimizing financial risks.

2. High cost base

OPG's high cost base has resulted in several disallowances by the OEB. For the 2022–26 rates decision, the Company agreed, in a settlement proposal with intervenors, to reduce its non-Darlington-Refurbishment-related regulated nuclear operations, maintenance, and administration (OM&A) budget by 3% annually (total of $277 million over the five-year term). Morningstar DBRS believes that OPG's inability to fully recover compensation costs in future regulated prices could have a negative impact on earnings and affect the Company's ability to achieve its approved return on equity (ROE).

3. Limited nuclear waste management liabilities

Morningstar DBRS notes the used fuel obligation is funded by the used fuel fund, which was over funded as at December 31, 2023. The Province provides a guarantee for any shortfall between the value of the nuclear fund and the CNSC consolidated financial guarantee requirement.

Environmental, Social, and Governance (ESG) Checklist

ESG Factor		ESG Credit Consideration Applicable to the Credit Analysis: Y/N		Extent of the Effect on the ESG Factor on the Credit Analysis: Relevant (R) or Significant (S)*
Environmental		**Overall:**	**N**	**N**
	Emissions, Effluents, and Waste	Do we consider that the costs or risks for the issuer or its clients result, or could result, in changes to an issuerÆs financial, operational, and/or reputational standing?	**N**	**N**
	Carbon and GHG Costs	Does the issuer face increased regulatory pressure relating to the carbon impact of its or its clients' operations resulting in additional costs and/or will such costs increase over time affecting the long-term credit profile?	**N**	**N**
	Resource and Energy Management	Does the scarcity of sourcing key resources hinder the production or operations of the issuer, resulting in lower productivity and therefore revenues?	**N**	**N**
	Land Impact and Biodiversity	Is there a financial risk to the issuer for failing to effectively manage land conversion, rehabilitation, land impact, or biodiversity activities?	**N**	**N**
	Climate and Weather Risks	In the near term, will climate change and adverse weather events potentially disrupt issuer or client operations, causing a negative financial impact? In the long term, will the issuer's or client's business activities and infrastructure be materially affected financially under key IPCC climate scenarios up to a 2°C rise in temperature by 2050?	**N**	**N**
Social		**Overall:**	**N**	**N**
	Social Impact of Products and Services	Do we consider that the social impact of the issuer's products and services pose a financial or regulatory risk to the issuer?	**N**	**N**
	Human Capital and Human Rights	Is the issuer exposed to staffing risks, such as the scarcity of skilled labour, uncompetitive wages, or frequent labour relations conflicts, that could result in a material financial or operational impact?	**N**	**N**
		Do violations of rights create a potential liability that can negatively affect the issuer's financial wellbeing or reputation?	**N**	**N**
		Human Capital and Human Rights:	**N**	**N**
	Product Governance	Does failure in delivering quality products and services cause damage to customers and expose the issuer to financial and legal liability?	**N**	**N**
	Data Privacy and Security	Has misuse or negligence in maintaining private client or stakeholder data resulted, or could it result, in financial penalties or client attrition to the issuer?	**N**	**N**
	Occupational Health and Safety	Would the failure to address workplace hazards have a negative financial impact on the issuer?	**N**	**N**
	Community Relations	Does engagement, or lack of engagement, with local communities pose a financial or reputational risk to the issuer?	**N**	**N**
	Access to Basic Services	Does a failure to provide or protect with respect to essential products or services have the potential to result in any significant negative financial impact on the issuer?	**N**	**N**
Governance		**Overall:**	**N**	**N**
	Bribery, Corruption, and Political Risks	Do alleged or actual illicit payments pose a financial or reputational risk to the issuer?	**N**	**N**
		Are there any political risks that could affect the issuer's financial position or its reputation?	**N**	**N**
		Bribery, Corruption, and Political Risks:	**N**	**N**
	Business Ethics	Do general professional ethics pose a financial or reputational risk to the issuer?	**N**	**N**
	Corporate / Transaction Governance	Does the issuer's corporate structure allow for appropriate board and audit independence?	**N**	**N**
		Have there been significant governance failures that could negatively affect the issuer's financial wellbeing or reputation?	**N**	**N**
		Does the board and/or management have a formal framework to assess climate-related financial risks to the issuer?	**N**	**N**
		Corporate / Transaction Governance:	**N**	**N**
		Consolidated ESG Criteria Output:	**N**	**N**

ESG Considerations

Environmental

There were no Environmental factors that had a relevant or significant effect on the credit analysis. Morningstar DBRS notes OPG operates the Darlington and Pickering GSs, which creates nuclear by-products such as used fuel, and low-level and intermediate-level materials. OPG's nuclear operations and handling of nuclear by-products are regulated by the CNSC. The Company also has nuclear fixed asset removal and nuclear waste management funds for costs to be incurred for the safe storage of nuclear materials, and for the eventual dismantlement of the facilities and remediation of the land. As at December 31, 2023, the Decommissioning Segregated Fund was overfunded by 37%, and the Used Fuel Segregated Fund was overfunded by 7%. Morningstar DBRS expects costs associated with OPG's handling of nuclear by-products to be funded through regulated rates.

Social

There were no Social factors that had a relevant or significant effect on the credit analysis. Morningstar DBRS notes, as a regulated utility, OPG provides an essential service. Any unplanned outages in the Company's operations could significantly affect its reputation and could lead to financial penalties. OPG's nuclear operations are regulated by the CNSC to ensure compliance with nuclear facility security measures, environmental matters, and safety operations. The Company is subject to audits and inspections against CNSC license and performance objectives. Canada is also signatory to various international conventions relating to nuclear energy and emergency responses. OPG is also committed to workplace health and safety, using an integrated health and safety management system and operational risk control procedures. As many of the Company's generation assets are within the treaty and traditional territories of Indigenous peoples, OPG also has an Indigenous Relations Policy and Reconciliation Action Plan to engage and collaborate with Indigenous communities across the province.

Governance

There were no Governance factors that had a relevant or significant effect on the credit analysis. OPG has a Memorandum of Agreement (MOA) with its shareholder, the Province, on the governance, performance and communication of the Company. The MOA underlines the Province's expectation that OPG's board of directors is responsible for overseeing management of the Company, and to operate as a business enterprise with a commercial mandate. OPG's board sets the policies for the Company, including on diversity and inclusion, business conduct, conflict of interest, and cybersecurity.

A description of how Morningstar DBRS considers ESG factors within the Morningstar DBRS analytical framework can be found in *Morningstar DBRS Criteria: Approach to Environmental, Social, and Governance Risk Factors in Credit Ratings* at https://dbrs.morningstar.com/research/427030.

Rating History

	Current	2023	2022	2021	2020	2019
Issuer Rating	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Unsecured Debt	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

Previous Report

- Ontario Power Generation Inc.: Rating Report, May 8, 2023.

Previous Actions

- "DBRS Morningstar Confirms Ontario Power Generation Inc. at A (low)/R-1 (low), Stable Trends," April 11, 2023.

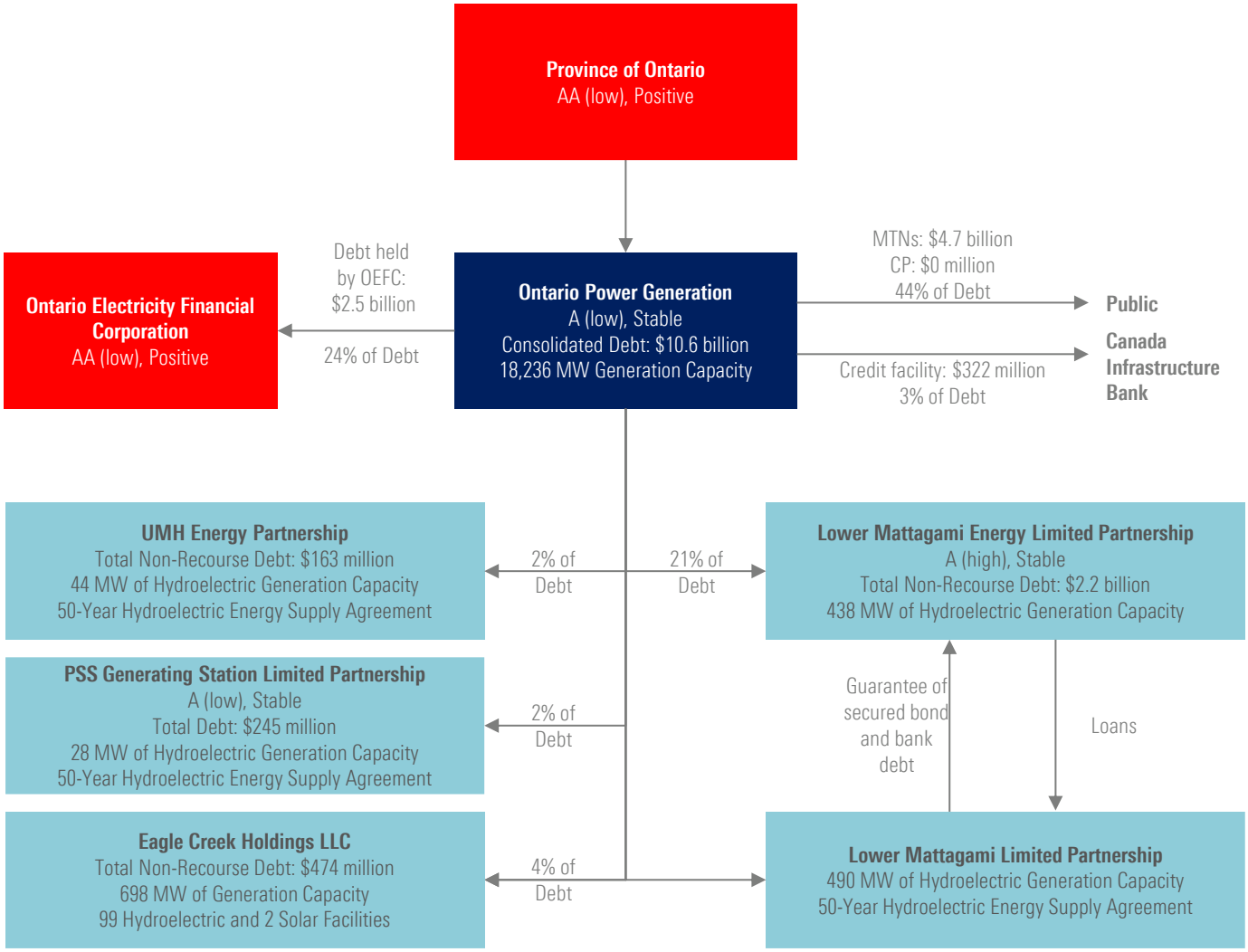
Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on https://dbrs.morningstar.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

Appendix 1—Company Profile

Exhibit 1 Organizational Chart



As at December 31, 2023.
Source: OPG.

- As at December 31, 2023, debt at the OPG corporate level consists of $2.5 billion held by the OEFC, $4.7 billion of medium-term notes (MTNs), and $322 million drawn under a credit facility provided by the Canada Infrastructure Bank (CIB).
    - Debt at UMH, LMELP, and Eagle Creek Holdings LLC (Eagle Creek) are secured by the assets at each corresponding subsidiary and are nonrecourse to the Company.
    - Debt at PSS is recourse to OPG until the recourse release date.

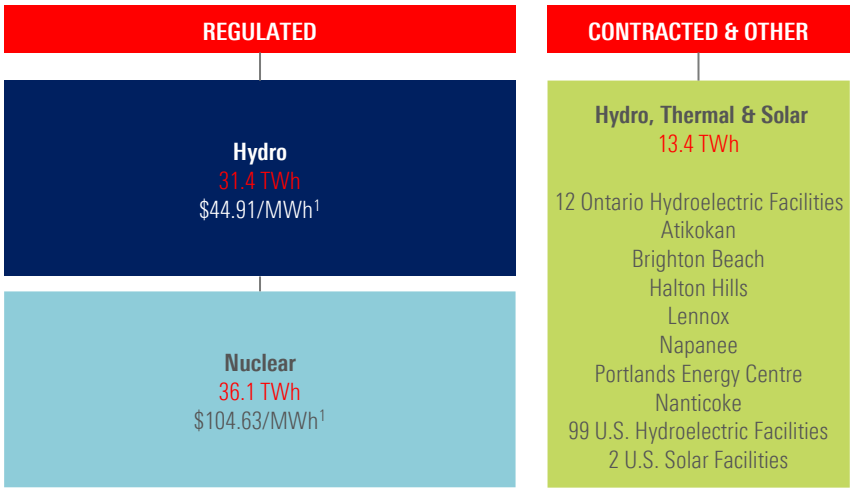
Generation Profile

As at December 31, 2023	Percent (%)	Capacity (MW)
Nuclear		
Darlington	10%	1,756
Pickering A	6%	1,030
Pickering B	11%	2,064
	27%	**4,850**
Thermal		
Atikokan (Biomass)	1%	205
Brighton Beach	3%	570
Halton Hills	4%	683
Napanee	5%	900
Portlands Energy Centre	3%	562
Lennox (Dual oil & gas)	12%	2,100
	28%	**5,020**
Hydroelectric		
Contracted[1]	10%	1,756
Regulated	36%	6,566
	46%	**8,292**
Other		
Solar[2]	0%	44
Total Capacity	**100%**	**18,236**

1 Includes plants under an Energy Supply Agreement (ESA) or a long-term contract.
2 Three solar facilities.

- OPG is the largest generator of electricity in Ontario.
  - In 2023, the Company generated 80.9 terawatt hours of electricity.
- OPG also owns the Bruce A and Bruce B Nuclear GS, which are leased on a long-term basis to Bruce Power L.P. (rated BBB with a Stable trend by Morningstar DBRS).

Exhibit 2 Price Structure



1 Rates as of January 1, 2024.
For the year ended December 31, 2023.
Source: OPG.

- OPG sells electricity to consumers through the IESO.
- Regulated facilities sell at rates set by the OEB, which could include rate riders used for the recovery of nuclear deferral and hydroelectric variance account balances.
- The Contracted and Other Portfolio includes (1) assets in Ontario that sell electricity at prices set through ESAs or other long-term contracts with the IESO and (2) Eagle Creek, which holds interest in 99 U.S. hydroelectric GS and two U.S. solar facilities.
    - The Eagle Creek facilities either sell into the merchant market or operate under long-term energy or capacity supply contracts.

Appendix 2—Major Projects

Project	Estimated Cost (CAD millions)	Spent as of Dec. 31, 2023 (CAD millions)	In-Service Target Date
Darlington Refurbishment	12,800	10,203	2026[1]
Little Long Dam Safety Project	700	637	2023
Smoky Falls Dam Safety Project	390	239	2024
Atura Power Development Projects	850	82	2026[2]

1 Four units with staged in-service. Last unit scheduled to be completed by 2026.
2 Niagara Hydro Centre (NHC) scheduled to be completed in 2025 and Napanee BESS projects scheduled to be completed in 2026.

- **Darlington Refurbishment**: The Darlington Refurbishment will extend the operating life of the Darlington GS by at least 30 years. The execution of the refurbishment of the first unit began in October 2016, and the last unit is scheduled to be completed by 2026. Construction on the first unit was completed in March 2020 and returned in service in June 2020. Refurbishment on the second unit began in September 2020 after a short delay related to the coronavirus pandemic, and was placed back in service in July 2023, ahead of schedule. Refurbishment on the third unit began in February 2022 and is scheduled to be returned to service in Q2 2025. Refurbishment on the fourth unit began in July 2023 and is scheduled to be returned to service by the end of 2026. The project remains on schedule and on budget.
- **Little Long Dam Safety Project**: This project is intended to make reliability and operational improvements and increase the discharge capacity at the Little Long Dam. The Little Long Dam supports hydroelectric GSs on the Lower Mattagami River.
- **Smoky Falls Dam Safety Project**: This project is intended to improve dam safety at the Smoky Falls hydroelectric GS.
- **Atura Power Development Projects**: This project includes (1) the construction of an electrolyzer for large-scale hydrogen production using hydro power in Niagara Falls, Ontario, and (2) a 250 MW battery energy storage system at the Napanee GS site. The NHC is expected to be completed in 2025 while the Napanee BESS is expected to be completed in 2026 and operate under a capacity agreement with the IESO.
- **Pickering Refurbishment**: In June 2023, OPG applied to the CNSC to extend the life of the Pickering Nuclear GS to September 2026. In January 2024, the Province approved for the Company to begin engineering and design work, and to secure long-lead components to refurbish four units of the Pickering Nuclear GS to extend the operating life by at least 30 years.
- **Darlington New Nuclear Project**: This project involves constructing Canada's first grid-scale SMR at the Darlington site. OPG has applied to the CNSC for a license to construct, with a preliminary schedule of completing construction by 2028 with commercial operation in 2029. In July 2023, the Province announced for the Company to proceed with planning and licensing for three additional SMRs at the Darlington site, with in-service dates for the three additional units in the mid-2030s.

Appendix 3—Regulation

- OPG benefits from a reasonably regulated environment. As at December 31, 2023, approximately 63% of its installed in-service capacity is regulated.
    - OPG, regulated by the OEB under the Ontario Energy Board Act, 1998, is allowed to receive regulated prices for all electricity generated from its nuclear facilities (4,850 MW) as well as most of its hydroelectric power facilities in Ontario (6,565 MW).
- In November 2020, the Province amended Ontario Regulation (O. Reg.) 53/05 (O. Reg. 53/05) to freeze hydroelectric base rates for OPG at the 2021 level for the next regulatory period of 2022–26.
    - Morningstar DBRS notes the hydroelectric rate freeze may modestly pressure the Company's earnings as OPG will have to find efficiencies in its regulated hydroelectric operations to offset inflationary cost increases.
- In November 2021, the OEB issued its decision on OPG's application for rates effective January 1, 2022.
    - The OEB approved a settlement proposal between OPG and intervenors as filed.
    - As per O. Reg. 53/05, hydroelectric base payment amounts will remain at the 2021 level.
    - Capital structure will remain at 55% debt (the Company had requested a change to 50% debt) and an allowed ROE of 8.66%.
    - For nuclear facilities, the continuation of the current Custom IR methodology along with a rate-smoothing deferral account (as required under O. Reg. 53/05).
    - Under Custom IR, nuclear revenue requirements were determined by a five-year forecast cost-of-service (COS) approach, but with a stretch factor of 0.6% applied to the Company's OM&A expenditures for 2023–25 (compared with 0.45% as requested), and 0.3% for 2026. The reduction in OM&A costs as a result of the stretch factor will accumulate for the five-year period.
    - The rate-smoothing deferral account will stabilize year-to-year changes to weighted-average payment amounts as the Darlington Refurbishment continues. OPG will defer a portion of its approved nuclear revenue requirements into the rate-smoothing deferral account and will be allowed to recover the deferred amount over a 10-year period once the Darlington Refurbishment has been completed.
    - Total regulated nuclear revenue requirement of $16.0 billion over the five-year term, representing a $567 million reduction (including a 3%, or $277 million, reduction of OM&A costs) from the Company's application.
    - The OEB approved the inclusion of $8.6 billion to the rate base (including $6.4 billion for the Darlington Refurbishment) over the five-year period of the Custom IR (reduction of $298 million for planned non-Darlington Refurbishment in-service capital add-ons). Any Darlington Refurbishment cost overruns will be subject to a prudence review before being added to the rate base.
    - Inclusion of $396 million to the rate base for the Heavy Water Storage and Drum Handling Facility project (in-service 2020); this represents a permanent rate base reduction for the

project of $94 million plus carrying costs incurred from May 2017 to March 2020 for capital cost deemed not prudently incurred.

- Recently completed non-Darlington Refurbishment capex of $358 million, which exceeded the 2017–21 approved in-service capital additions, will earn an ROE at the cost of long-term debt (3.6% for the 2022 to 2026 rate period) instead of the allowed ROE until 2037.
- The OEB approved the recovery of balances as at December 31, 2019, in OPG's deferral and variance accounts. The OEB also approved a $47 million credit to customers for the impact of favourable electricity revenue during the 2020 and 2021 Coronavirus (COVID-19) Disease pandemic response (net of any incremental pandemic-related OM&A).
- All previously existing regulatory accounts will continue, along with new accounts to track (1) any financial impact from a possible transition to and implementation of IFRS from US GAAP, (2) revenue requirement impact for a planned new corporate campus, and (3) any revenue requirement impact to nuclear liabilities and depreciation expense from accounting end-of-life assumptions for the Pickering GS.
- An earnings-sharing mechanism was also approved, where regulated earnings 100 basis points above the approved ROE over the cumulative five-year term will be shared 50-50 with customers.

Approved Regulated Nuclear Amounts	2022	2023	2024	2025	2026
Nuclear revenue requirement (CAD millions)	3,515.5	3,430.0	3,518.3	3,197.6	2,439.5
Nuclear rate base (CAD millions)	8,600.3	8,615.0	11,033.4	12,188.8	12,991.8
Nuclear payment amount (CAD per MW hour (MWh))	105.22	109.04	104.63	108.19	118.91
Hydro payment amount (CAD per MWh)	44.91	44.91	44.91	44.57	44.57

- In June 2023, OPG filed an application with the CNSC to extend operating Pickering GS to September 2026.
    - In December 2022, the Province amended O. Reg. 53/05 to require OPG to establish a variance account to track the additional revenues and costs associated with operating Units 5 to 8 of the Pickering GS between January 1 and September 30, 2026. The disposition of the account balance will be subject to the OEB's prudence review and approval in a future proceeding.
    - In January 2024, the Province approved for the Company to commence the Project Initiation Phase, at a budget of $2 billion, for the refurbishment of units 5-8 at Pickering GS.
- Effective January 1, 2022, O. Reg. 53/05 was amended so that any SMR constructed at the Darlington site will be considered a regulated facility prescribed under OEB regulation.

Assessment of Regulatory Framework

Criteria	Score	Analysis
1. Deemed Equity	Excellent **Good** Satisfactory Below Average Poor	The OEB allows OPG to have a deemed equity of 45%.
2. Allowed ROE	Excellent Good **Satisfactory** Below Average Poor	OPG has an allowed ROE of 8.66% for 2022–26 (based on nuclear regulated rates), which is in line with the other regulated utilities in Ontario. Any difference in ROE between the Company and other regulated utilities in the province is mainly because of the timing of the regulatory filings and the interest environment prevalent at that time.
3. Energy Cost Recovery	Excellent Good Satisfactory Below Average Poor	N/A; energy costs are recovered through rates for OPG.
4. Capital and Operating Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	Under Custom IR for the nuclear facilities, the capex program for OPG is preapproved for a five-year period by the OEB and recovered through base rates. Future test years are used for nuclear rates applications. Some volume risk exists, but this is partly mitigated by (1) use of deferral accounts for volumetric differences, and (2) rates are based on forecasts which include scheduled outages. However, lost revenues resulting from forced outages beyond the forecast allowances are not recoverable through rates.
5. COS versus IRM	Excellent Good **Satisfactory** Below Average Poor	The nuclear facilities operate under Custom IR, which is a hybrid of COS and the IR framework, for a five-year term. Morningstar DBRS considers the Custom IR framework as reasonable.
6. Political Interference	Excellent Good Satisfactory **Below Average** Poor	The Government of Ontario plays a significant role in the electricity sector in Ontario, given that most of the utilities are government owned (OPG is owned by the Province). Furthermore, stakeholders, such as the IESO, are also government owned. As a result, the government has direct and indirect influence on Ontario's electricity industry.
7. Stranded Cost Recovery	Excellent Good **Satisfactory** Below Average Poor	Regulated utilities in Ontario have a limited history of stranded costs. Most prudently incurred or budgeted capex is approved by the OEB. While OPG has seen some write-downs, these have been because the OEB had deemed the costs overruns to have been imprudent.
8. Rate Freeze	Excellent Good Satisfactory **Below Average** Poor	Morningstar DBRS notes that, in November 2020, the Province amended O. Reg. 53/05 to freeze hydroelectric base rates for the Company at the 2021 level for the next regulatory period from 2022 to 2026. Rates for nuclear facilities were not frozen and have been set by the OEB. Morningstar DBRS notes that the hydroelectric rate freeze may modestly pressure OPG's earnings as the Company will have to find efficiencies to offset inflation.

Exhibit 4—Long-term Debt and Credit Facilities

Long-term Debt

(CAD millions as at December 31, 2023)	Maturity	Amount
Notes payable to the OEFC	2025-2048	2,500
Medium Term Note Program	2025-2051	4,650
Canada Infrastructure Bank term credit facility	2027[3]	322
UMH[1]	2041	163
PSS[2]	2067	245
LMELP[1]	2024-2052	1,995
Eagle Creek[1]	2025-2030	474
Other		25
Subtotal		**10,374**
Less: Fair value discount		5
Less: Bond issuance fees		(37)
Less: Current portion		(603)
Total long-term debt		**9,739**

1 Nonrecourse to OPG as debt is secured by assets of the associated project.
2 Secured by assets of the projects; recourse to OPG until the recourse release date.
3 The availability period to borrow under the facility is expected to end by September 2027, and amounts drawn under the facility have an expected maturity date of September 2042, subject to certain conditions.

- Debt at UMH, LMELP, and Eagle Creek are secured by assets of the associated project and nonrecourse to OPG. Debt at PSS is secured by assets of the project and are recourse to OPG until the recourse release date.

Maturity Profile

(CAD million as at December 31, 2023)	2024	2025	2026	2027	2028	Thereafter	Total
Long-term debt	603	588	674	530	248	7,731	**10,374**
	6%	6%	6%	5%	2%	75%	**100%**

- OPG's maturity profile is fairly spread out.

Credit Facilities

(CAD million as at December 31, 2023)	Maturity	Amount	Drawn/LOC	Available
Committed credit facility	May 2028	1,000	0	1,000
Committed credit facility–USD 750 million	Nov. 2024	992	0	992
OEFC general corporate credit facility	Dec. 2026	750	0	750
Canada Infrastructure Bank term credit facility[2]	Sep. 2027	970	322	648
Short-term uncommitted credit facilities	Demand	665	450	215
Short-term uncommitted overdraft facilities	Demand	25	0	25
Lower Mattagami River Project[1]	Aug. 2028	460	60	400
UMH credit facilities[1]	Oct. 2025	16	15	1
UMH overdraft facilities[1]	Oct. 2025	8	0	8
Eagle Creek credit facility–USD 20 million[1]	Oct. 2028	26	0	26
Subtotal		**4,913**	**847**	**4,066**
CPs–corporate			0	0
CPs–LMELP			200	(200)
Total		**4,913**	**1,047**	**3,866**

1 Nonrecourse to OPG as debt is secured by assets of the associated project.
2 The availability period to borrow under the facility is expected to end by September 2027, and amounts drawn under the facility have an expected maturity date of September 2042, subject to certain conditions.

- OPG has a reasonable liquidity profile.
- The Company has a $1.0 billion Canadian CP program (none outstanding as at December 31, 2023) and a USD 750 million CP program in the U.S. (none outstanding as at December 31, 2023; unrated by Morningstar DBRS). These CP programs are supported by the following facilities:
    - Committed bank facility of $1.0 billion (due date of May 2028);
    - A USD 750 million bank facility (due date of November 2024, with a one-year term-out option); and
    - An OEFC facility of $750 million (due date of December 2026).
- In August 2022, OPG entered into a $970 million non-revolving term credit facility with the CIB. The facility will be available to borrow on until September 2027, with any outstanding amounts to have an extended maturity date of September 2042, subject to certain conditions.
- The LMELP, UMH, and Eagle Creek facilities are used to support the respective projects and are nonrecourse to OPG.

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Credit Rating Report
Ontario Power Generation Inc.

Morningstar DBRS
April 21, 2025

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Commercial Paper Limit
CAD 1.0 billion and USD 750 million

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Credit Ratings

Obligation	Credit Rating	Credit Rating Action	Trend
Issuer Rating	A (low)	Confirmed	Stable
Unsecured Debt	A (low)	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Credit Ratings Drivers

Positive Credit Rating Drivers	Negative Credit Rating Drivers
We believe a positive credit rating action is unlikely over the medium term given the business profile and the ongoing significant and complex capital expenditures (capex) program.	We could take a negative credit rating action should there be cost overruns that result in significant stranded costs and lack of support from the Province of Ontario.

Key Credit Rating Considerations

We based our credit ratings on Ontario Power Generation Inc. (OPG or the Company) on its regulated generation business, which operates under a reasonable regulatory regime under the Ontario Energy Board (OEB). The Stable trends reflect the Company's key credit metrics, which remain reasonable despite the complex and substantial capex program.

We note that OPG has a number of large capital projects ongoing. The Darlington Refurbishment Project, with total capex of $12.8 billion, is on track and on schedule. The refurbished Unit 3 and Unit 1 were reconnected to the electricity grid ahead of schedule in 2023 and 2024, respectively. Unit 4 is currently executing reassembly. The start of Unit 4 marks the last of the four units being refurbished in Darlington, Ontario, and is scheduled to be returned to service in 2026. The Pickering Refurbishment Project, which aims to refurbish Units 5-8 of the Pickering Nuclear Generating Station (GS), is anticipated to return the units to service by the mid-2030s. In January 2025, the Province of Ontario (the Province or Ontario; 100% owner of OPG; rated AA with a Stable trend) approved OPG's plan to proceed with the project definition phase as the next step toward the refurbishment. OPG's approved budget for this work is $4.1 billion, bring the total board-approved budget for the project to date to $6.2 billion.

Darlington's Small Modular Reactor (SMR) Unit 1 is expected to begin commercial operation by the end of 2030. OPG is also planning for three additional SMRs at the Darlington site. On April 4, 2025, the Canadian Nuclear Safety Commission (CNSC) granted OPG a licence to construct one SMR. Issuance of the licence to construct is a key milestone for the SMR project as it shows continued confidence from the Canadian nuclear regulator in OPG executing the SMR project.

Additionally, the wholly owned subsidiary Atura Power, as part of OPG's nonregulated segment, is constructing three projects, namely Niagara Hydrogen Center, Napanee battery energy storage system (BESS), and Napanee GS expansion, with a total capital budget of $1.5 billion. With the electrification of the economy and the expected increase in electricity demand in the Province, the Company also intends to pursue opportunities to increase generation capacity such as through Independent Electricity System Operator (IESO) request for proposals or the development of hydro sites throughout the Province.

Financial Outlook

Given these ongoing projects, in 2024 the Company reported a total capex of $3.5 billion, representing an increase of 22% compared with 2023. Over the 2025–26 period, OPG plans to invest approximately $12.7 billion in its generating fleet and other growth initiatives and subsidiaries. Capex remaining at this level in the near term will likely result in substantial net free cash flow deficits that will require debt financing. The Company is currently exploring additional credit supportive funding sources funding sources, which would reduce its debt needs. While most of OPG's projects are regulated and will be added to the Company's rate base when completed, there is significant execution risk because of the complexity and scale of the projects.

We have factored into OPG's current credit ratings that its key credit metrics will weaken moderately over the medium term, but, given the complexity of the projects, the key credit metrics remain reasonable for the A (low) credit rating. We will continue to monitor progress on the Darlington and Pickering refurbishment projects, the SMR project, and Federal and Provincial funding programs, and we expect that the Company will not undertake any major capex without having financing and a cost-recovery mechanism in place to minimize financial risks.

Earnings Outlook

OPG's net income for 2024 was $988 million, a decrease of 43% compared with 2023 because of (1) higher planned outage days on Unit 2 at the Darlington GS; (2) a planned shutdown of Unit 1 of the Pickering GS during 2024 resulting in lower nuclear production and higher operations, maintenance, and administrative costs; and (3) lower regulated nuclear prices being in effect for 2024. OPG expects earnings in 2025 to be higher than in 2024, reflecting the positive impact of a full year of the Darlington GS Unit 1 returning to service and no other major outages planned at Darlington. Overall, we expect future earnings volatility to come primarily from forecast risk as part of the regulatory process.

Financial Information

	For the year ended December 31				
	2024	**2023**	**2022**	**2021**	**2020**
Cash flow/total debt (%)	23.5	31.3	31.3	31.3	31.8
Total debt in capital structure (%)[1]	35.7	34.0	35.2	36.5	39.6
EBIT gross interest coverage (times)	3.25	5.37	5.35	4.73	5.00

1 Adjusted for Accumulated Other Comprehensive Income.
Note: Morningstar DBRS no longer excludes nonrecourse debt in its calculation of key metrics.

Issuer Description

OPG is an electricity generation company with a diverse portfolio of more than 18,000 MW of in-service generating capacity. The Company is wholly owned by the Province.

Business Risk Assessment

1. Reasonable regulatory framework that provides stable cash flow

The reasonable regulatory framework has allowed OPG to recover prudently incurred costs and provided stable cash flows. We note, however, that there have been disallowances by the OEB in the past on labour compensation costs related to the Company's nuclear operations. We also note that, under an incentive rate-setting (IR) framework and the regulated hydroelectric rate freeze, OPG's profitability could come under further pressure because of the need to meet efficiency and productivity benchmarks.

2. Support of shareholder (the Province)

The Province indirectly provides OPG with some of its long-term funding requirements through the Ontario Electricity Financial Corporation (OEFC; rated AA with a Stable trend), a government financing arm for provincial power companies. As at December 31, 2024, OPG had approximately $2.1 billion of notes payable to the OEFC, comprising 18% of the Company's outstanding debt. We believe that the Province will continue to support its investment because OPG is a creation of the Province and is integral to fulfilling Ontario's energy needs. OPG's importance in Ontario is also demonstrated by the fact that it is the primary electricity generator in Ontario, accounting for approximately 57% of electricity produced in 2024. While OPG's debt is not directly guaranteed by the Province, we believe that the Province will, in exceptional circumstances, provide support to the Company.

3. Nuclear generation risks

Nuclear generation, which represented approximately 40% of OPG's production in 2024, faces higher operating risks than other types of power generation because of its complex technology. The financial implications of forced outages are greater, given the high fixed-cost nature of these plants and because lost revenues resulting from outages are not recoverable through rates.

4. Political intervention

OPG is subject to political intervention, largely because of its ownership by the Province and changes in government mandates and policies. We note that, though the Province has committed to having the Company run more autonomously, the risk of further government intervention still exists. In November 2021, the OEB issued a decision to freeze OPG's regulated hydroelectric base rates at the 2021 level for the following regulatory period of 2022–26. We expect the Company's earnings to be modestly pressured as OPG will have to find efficiencies to offset inflationary cost increases.

5. Exposure to nonregulated operations

OPG owns several nonregulated generation assets, including gas-fired plants in Ontario and a renewable facility operator and developer in the U.S. The Company also owns nonregulated natural gas, oil, solar, and biomass generation assets in the Province. While the Ontario assets are largely under long-term contracts with strong investment-grade counterparties, such as the IESO, and contribute relatively stable

earnings and cash flow, we view nonregulated assets as generally having higher business risks than the incumbent regulated operations because there is less cost recovery certainty and potentially more volatile cash flow.

We note earnings contributed by regulated operations may fluctuate over the near term, resulting in nonregulated earnings to be near or modestly more than the 20% threshold as the ongoing Darlington Refurbishment project and the expected Pickering Refurbishment constrict output. The Company has indicated that growth in its nonregulated business will be at a more moderate pace going forward, with most planned capex for its regulated operations. As such, contributions from regulated operations are likely to remain higher than 80% over the long term, especially once the Darlington Refurbishment is completed in 2026. Additionally, we also consider assets under regulatory-styled contracts to have similar credit risks as regulated operations because those contracts mimic the current regulatory construct under the OEB; we estimate an EBITDA contribution of 86% from regulated operations and assets under regulatory-styled contracts in 2024. Examples of such assets include Lower Mattagami Energy Limited Partnership (LMELP; rated A (high) with a Stable trend), PSS Generating Station LP (New Post Creek) (PSS; rated A (low) with a Stable trend), and UMH Energy Partnership (UMH). However, should OPG pursue acquisitions that result in a significant shift in the EBITDA mix between regulated and nonregulated operations, or lead to credit metrics deteriorating to a level no longer supportive of the current rating category, we could take a negative credit rating action.

6. Tariff impact

OPG has low exposure to potential tariff risks because of its strong reliance on Canadian-based labour and suppliers, with over 90% of nuclear and hydroelectric procurement sourced domestically. OPG has established an internal Tariff Taskforce and is promoting made-in-Canada technologies. The Company's key projects are part of its regulated operations; financial exposure from tariff-related costs variances may be recoverable through regulatory deferral accounts.

Financial Risk Assessment

1. Significant capex program

OPG has a significant capex program under way, with approximately $12.7 billion planned for 2025–26. We note that OPG has started the initial preparation work to refurbish four units at the Pickering GS. The recent granting of the construction licence paves the way for major progress on the Darlington SMR project in the next two or three years. These two projects would be complex undertakings and require significant financing. While capex for both these projects will be regulated and should lead to a substantial increase in the rate base, there is also considerable execution risk, which could lead to large cost overruns. We are encouraged by OPG's current track record with the Darlington Refurbishment, which remains on budget and on schedule. We also expect that the Company will not undertake any major capex without having financing and a cost-recovery mechanism in place, thus minimizing financial risks.

2. High cost base

OPG's high cost base has resulted in several disallowances by the OEB. For the 2022–26 rates decision, the Company agreed, in a settlement proposal with intervenors, to reduce its non-Darlington-Refurbishment-related regulated nuclear operations, maintenance, and administration (OM&A) budget by 3% annually: a total of $277 million over the five-year term. We believe that OPG's inability to fully recover compensation costs in future regulated prices could have a negative impact on earnings and affect the Company's ability to achieve its approved return on equity (ROE).

3. Limited nuclear waste management liabilities

We note that the used fuel obligation is funded by the Nuclear Segregated Funds, which were overfunded as at December 31, 2024. The Province provides a guarantee to the CNSC as required, should there be a shortfall between the value of the Nuclear Segregated Funds and the CNSC consolidated financial guarantee requirement.

Environmental, Social, and Governance (ESG) Checklist

ESG Factor		ESG Credit Consideration Applicable to the Credit Analysis: Y/N		Extent of the Effect on the ESG Factor on the Credit Analysis: Relevant (R) or Significant (S)*
Environmental		**Overall:**	**N**	**N**
	Emissions, Effluents, and Waste	Do we consider that the costs or risks for the issuer or its clients result, or could result, in changes to an issuerÆs financial, operational, and/or reputational standing?	**N**	**N**
	Carbon and GHG Costs	Does the issuer face increased regulatory pressure relating to the carbon impact of its or its clients' operations resulting in additional costs and/or will such costs increase over time affecting the long-term credit profile?	**N**	**N**
	Resource and Energy Management	Does the scarcity of sourcing key resources hinder the production or operations of the issuer, resulting in lower productivity and therefore revenues?	**N**	**N**
	Land Impact and Biodiversity	Is there a financial risk to the issuer for failing to effectively manage land conversion, rehabilitation, land impact, or biodiversity activities?	**N**	**N**
	Climate and Weather Risks	In the near term, will climate change and adverse weather events potentially disrupt issuer or client operations, causing a negative financial impact? In the long term, will the issuer's or client's business activities and infrastructure be materially affected financially under key IPCC climate scenarios up to a 2°C rise in temperature by 2050?	**N**	**N**
Social		**Overall:**	**N**	**N**
	Social Impact of Products and Services	Do we consider that the social impact of the issuer's products and services pose a financial or regulatory risk to the issuer?	**N**	**N**
	Human Capital and Human Rights	Is the issuer exposed to staffing risks, such as the scarcity of skilled labour, uncompetitive wages, or frequent labour relations conflicts, that could result in a material financial or operational impact?	**N**	**N**
		Do violations of rights create a potential liability that can negatively affect the issuer's financial wellbeing or reputation?	**N**	**N**
		Human Capital and Human Rights:	**N**	**N**
	Product Governance	Does failure in delivering quality products and services cause damage to customers and expose the issuer to financial and legal liability?	**N**	**N**
	Data Privacy and Security	Has misuse or negligence in maintaining private client or stakeholder data resulted, or could it result, in financial penalties or client attrition to the issuer?	**N**	**N**
	Occupational Health and Safety	Would the failure to address workplace hazards have a negative financial impact on the issuer?	**N**	**N**
	Community Relations	Does engagement, or lack of engagement, with local communities pose a financial or reputational risk to the issuer?	**N**	**N**
	Access to Basic Services	Does a failure to provide or protect with respect to essential products or services have the potential to result in any significant negative financial impact on the issuer?	**N**	**N**
Governance		**Overall:**	**N**	**N**
	Bribery, Corruption, and Political Risks	Do alleged or actual illicit payments pose a financial or reputational risk to the issuer?	**N**	**N**
		Are there any political risks that could affect the issuer's financial position or its reputation?	**N**	**N**
		Bribery, Corruption, and Political Risks:	**N**	**N**
	Business Ethics	Do general professional ethics pose a financial or reputational risk to the issuer?	**N**	**N**
	Corporate / Transaction Governance	Does the issuer's corporate structure allow for appropriate board and audit independence?	**N**	**N**
		Have there been significant governance failures that could negatively affect the issuer's financial wellbeing or reputation?	**N**	**N**
		Does the board and/or management have a formal framework to assess climate-related financial risks to the issuer?	**N**	**N**
		Corporate / Transaction Governance:	**N**	**N**
		Consolidated ESG Criteria Output:	**N**	**N**

ESG Considerations

Environmental

There were no Environmental factors that had a relevant or significant effect on the credit analysis. OPG is actively addressing transition risks by implementing its Climate Change Plan, which includes a comprehensive strategy to mitigate potential impacts on the organization. The Company also invests in resilient infrastructure, enhances emergency preparedness, and adopts advanced technologies to improve operational efficiency. We note that OPG operates the Darlington and Pickering GSs, which create nuclear by-products such as used fuel and low- and intermediate-level materials. OPG's nuclear operations and handling of nuclear by-products are regulated by the CNSC. The Company also has nuclear fixed-asset removal and nuclear waste management funds for costs to be incurred for the safe storage of nuclear materials and for the eventual dismantlement of the facilities and remediation of the land. As at December 31, 2024, the Decommissioning Segregated Fund was overfunded by 47% and the Used Fuel Segregated Fund was overfunded by 10%. We expect costs associated with OPG's handling of nuclear by-products to be funded through regulated rates.

Social

There were no Social factors that had a relevant or significant effect on the credit analysis. We note that, as a regulated utility, OPG provides an essential service. Any significant unplanned outages in the Company's operations could affect its reputation and could impact financial performance. OPG's nuclear operations are regulated by the CNSC to ensure compliance with nuclear facility security measures, environmental matters, and safety operations. The Company is subject to audits and inspections against CNSC licence and performance objectives. Canada is also signatory to various international conventions relating to nuclear energy and emergency responses. OPG is also committed to workplace health and safety, using an integrated health and safety management system and operational risk control procedures. As many of the Company's generation assets are within the treaty and traditional territories of Indigenous peoples, OPG also has an Indigenous Relations Policy and Reconciliation Action Plan (RAP) to engage and collaborate with Indigenous communities across the Province. Since 2022, OPG has reached $198 million in Indigenous contract awards and $39.4 million in equity distributions to the Indigenous partners. The RAP committed the Company to grow its economic impact on Indigenous communities and businesses to $1 billion over 10 years.

Governance

There were no Governance factors that had a relevant or significant effect on the credit analysis. OPG has a Memorandum of Agreement (MOA) with its shareholder, the Province, on the governance, performance, and communications of the Company. The MOA underlines the Province's expectation that OPG's board of directors is responsible for overseeing management of the Company, which operates as a business enterprise with a commercial mandate. OPG's president and chief executive officer has a seat on the board. All other board members are independent. The board is responsible for approving numerous ESG-related policies for the Company, including those on environmental, diversity and inclusion, business conduct, conflict of interest, and cybersecurity.

Credit Rating History

	Current	2024	2023	2022	2021	2020
Issuer Rating	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Unsecured Debt	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)

Previous Report

- *Ontario Power Generation Inc.: Rating Report*, April 30, 2024

Previous Actions

- Morningstar DBRS Confirms Ontario Power Generation Inc. at A (low)/R-1 (low), Stable Trends, April 11, 2024

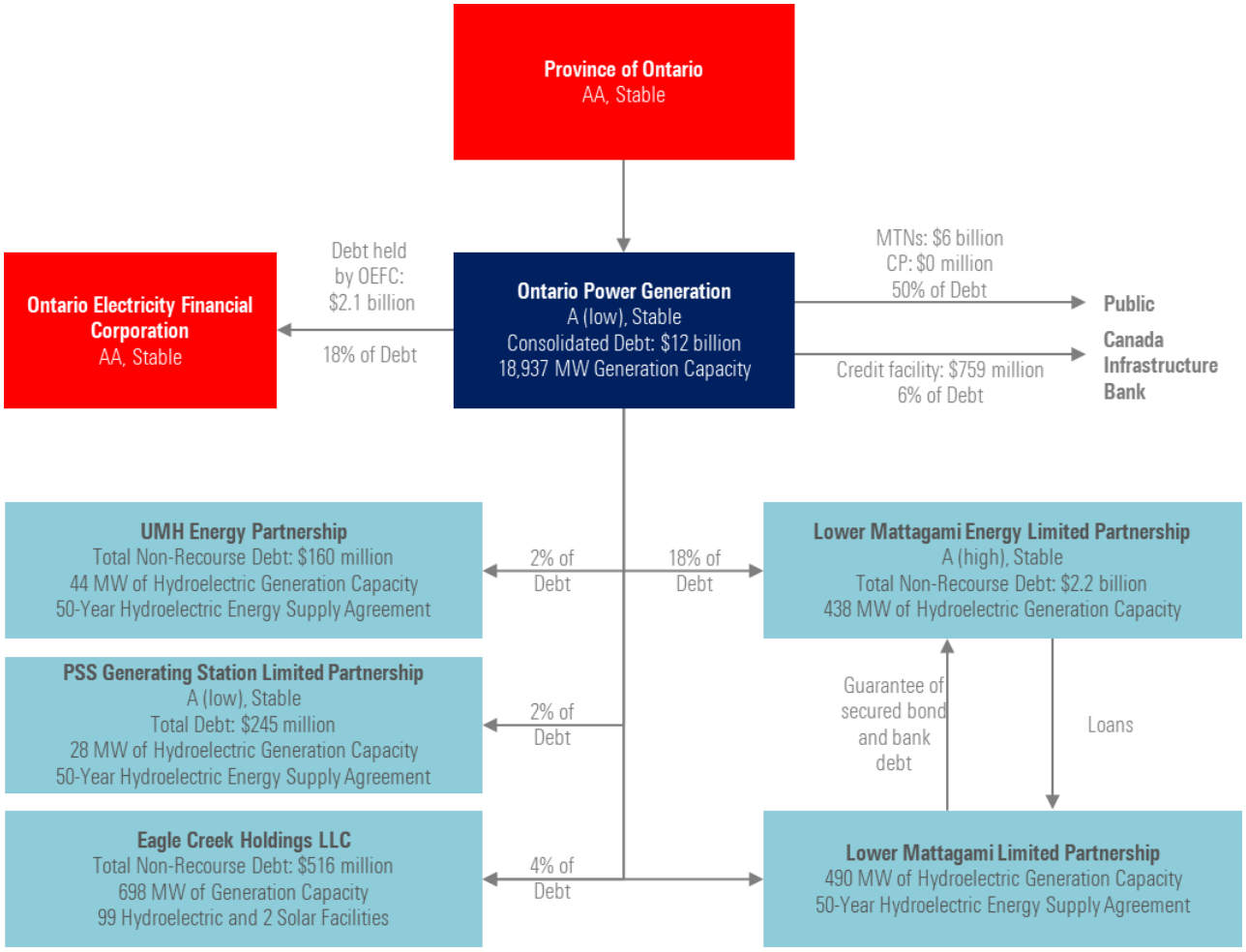
Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on https://dbrs.morningstar.com.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

Appendix 1—Company Profile

Exhibit 1 Organizational Chart



As at December 31, 2024.
Source: OPG.

- As at December 31, 2024, debt at the OPG corporate level consists of $2.1 billion held by the OEFC, $6 billion of medium-term notes, and $759 million drawn under a credit facility provided by the Canada Infrastructure Bank.
    - Debt at UMH, LMELP, and Eagle Creek Holdings LLC (Eagle Creek) are secured by the assets at each corresponding subsidiary and are nonrecourse to the Company.
    - Debt at PSS is recourse to OPG until the recourse release date.

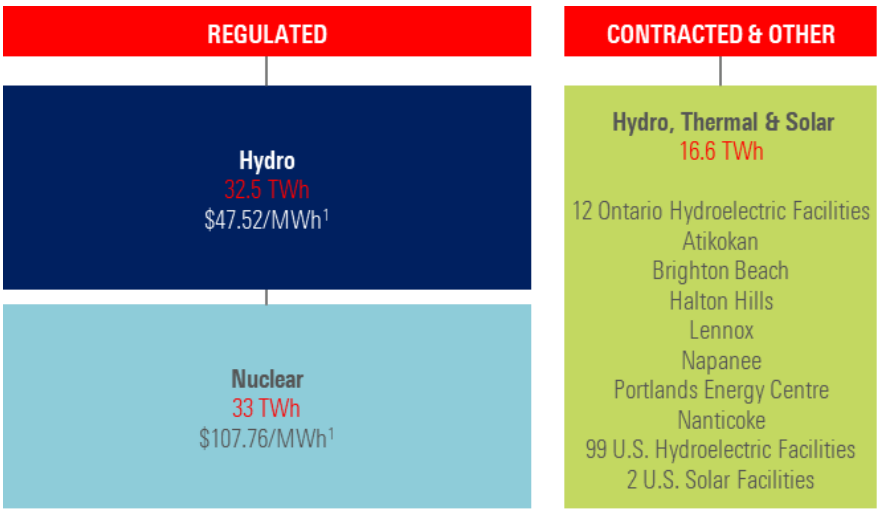
In-Service Generation Profile

As at December 31, 2024	Percent (%)	Capacity (MW)
Nuclear		
Darlington	15	2,634
Pickering	11	2,064
	26	**4,698**
Thermal		
Atikokan (Biomass)	1	180
Lennox (Dual oil & gas)	12	2,100
Atura Power[1]	15	2,715
	28	**4,995**
Hydroelectric		
Contracted[2]	10	1,756
Regulated	36	6,566
	46	**8,322**
Other		
Solar[3]	0	44
Total Capacity	**100**	**18,059**

1 Includes four facilities.
2 Includes plants under an Energy Supply Agreement (ESA) or a long-term contract.
3 Three solar facilities.

- OPG is the largest generator of electricity in Ontario. In 2024, the Company generated 82.1 terawatt hours of electricity.
- OPG also owns the Bruce A and Bruce B Nuclear GSs, which are leased on a long-term basis to Bruce Power L.P. (rated BBB with a Positive trend).

Exhibit 2 Price Structure



1 Rates as of January 1, 2025.
For the year ended December 31, 2024.
Source: OPG.

- OPG sells electricity to consumers through the IESO.
- Regulated facilities sell at rates set by the OEB, which could include rate riders used for the recovery of nuclear deferral and hydroelectric variance account balances.
- The Contracted and Other Portfolio includes (1) assets in Ontario that sell electricity at prices set through ESAs or other long-term contracts with the IESO and (2) Eagle Creek, which holds interest in 99 U.S. hydroelectric GSs and two U.S. solar facilities.
    - The Eagle Creek facilities either sell into the merchant market or operate under long-term energy or capacity supply contracts.

Appendix 2—Major Projects

Project	Estimated Cost (CAD millions)	Spent as of Dec. 31, 2024 (CAD millions)	In-Service Target Date
Darlington Refurbishment	12,800	11,190	2026[1]
Smoky Falls Dam Safety Project	390	327	2025[2]
Atura Power Development Projects	1,500	288	2026-2028[3]

1 Four units with staged in-service. Last unit scheduled to be completed by 2026.
2 The project has transitioned to site rehabilitation and closure activities, which will continue into 2025.
3 Scheduled completions: Niagara Hydrogen Centre – 2026; Napanee BESS – 2026; Napanee Combined Cycle GS Expansion Project – 2028.

- **Darlington Refurbishment**: The Darlington Refurbishment will extend the operating life of the Darlington GS by at least 30 years. The execution of the refurbishment of the first unit began in October 2016, and the last unit is scheduled to be completed by 2026. Construction on the first unit was completed in March 2020, and it returned into service in June 2020. Refurbishment on the second unit began in September 2020, after a short delay related to the coronavirus pandemic, and was placed back in service in July 2023, ahead of schedule. Refurbishment on the third unit began in February 2022 and was completed in November 2024, five months ahead of schedule. Refurbishment on the fourth unit began in July 2023 and the unit is scheduled to be returned to service by the end of 2026. The project remains on schedule and on budget.
- **Smoky Falls Dam Safety Project**: This project is intended to improve dam safety at the Smoky Falls hydroelectric GS. The major construction activities were completed in 2024.
- **Atura Power Development Projects**: The projects include (1) the construction of an electrolyzer for large-scale hydrogen production using hydro power in Niagara Falls, Ontario; (2) a 250 MW BESS at the Napanee GS site; and (3) a Napanee GS Expansion to add a hydrogen-ready simple-cycle combustion turbine generator unit that will provide up to 405 MW of electricity output to Ontario's electricity grid.
- **Pickering Refurbishment**: In June 2023, OPG applied to the CNSC to extend the life of the Pickering Nuclear GS to September 2026. In January 2024, the Province approved for the Company to begin engineering and design work and to secure long-lead components to refurbish four units of the Pickering Nuclear GS to extend the operating life by at least 30 years.
- **Darlington New Nuclear Project**: This project involves constructing Canada's first grid-scale SMR at the Darlington site. In July 2023, the Province announced for the Company to proceed with planning and licensing for three additional SMRs at the Darlington site, with in-service dates in the mid-2030s. On April 4, 2025, the CNSC granted OPG a licence to construct one SMR.

Appendix 3—Regulation

- OPG benefits from a reasonably regulated environment. As at December 31, 2024, approximately 63% of its installed in-service capacity was regulated.
    - OPG, regulated by the OEB under the Ontario Energy Board Act, 1998, is allowed to receive regulated prices for all electricity generated from its nuclear facilities (4,850 MW) as well as most of its hydroelectric power facilities in Ontario (6,565 MW).
- In November 2021, the Province amended Ontario Regulation (O. Reg.) 53/05 (O. Reg. 53/05) to freeze hydroelectric base rates for OPG at the 2021 level for the next regulatory period of 2022–26.
    - Morningstar DBRS notes the hydroelectric rate freeze may modestly pressure the Company's earnings as OPG will have to find efficiencies in its regulated hydroelectric operations to offset inflationary cost increases.
    - The next rate application will be filed before the end of 2025 and will be effective on January 1, 2027.
- In November 2021, the OEB issued its decision on OPG's application for rates effective January 1, 2022.
    - The OEB approved a settlement proposal between OPG and intervenors as filed.
    - As per O. Reg. 53/05, hydroelectric base payment amounts will remain at the 2021 level.
    - Capital structure will remain at 55% debt (the Company had requested a change to 50% debt) and an allowed ROE of 8.66%.
    - For nuclear facilities, the continuation of the current Custom IR methodology along with a rate-smoothing deferral account (as required under O. Reg. 53/05).
    - Under Custom IR, nuclear revenue requirements were determined by a five-year forecast cost-of-service (COS) approach, but with a stretch factor of 0.6% applied to the Company's OM&A expenditures for 2023–25, compared with 0.45% as requested, and 0.3% for 2026. The reduction in OM&A costs as a result of the stretch factor will accumulate for the five-year period.
    - The rate-smoothing deferral account will stabilize year-to-year changes to weighted-average payment amounts as the Darlington Refurbishment continues. OPG will defer a portion of its approved nuclear revenue requirements into the rate-smoothing deferral account and will be allowed to recover the deferred amount over a 10-year period once the Darlington Refurbishment has been completed.
    - Total regulated nuclear revenue requirement of $16.0 billion over the five-year term, representing a $567 million reduction (including a 3%, or $277 million, reduction of OM&A costs) from the Company's application.
    - The OEB approved the inclusion of $8.6 billion to the rate base, including $6.4 billion for the Darlington Refurbishment, over the five-year period of the Custom IR, representing a reduction of $298 million for planned non-Darlington Refurbishment in-service capital add-ons. Any Darlington Refurbishment cost overruns will be subject to a prudence review before being added to the rate base.

- Inclusion of $396 million to the rate base for the Heavy Water Storage and Drum Handling Facility project (in-service 2020); this represents a permanent rate base reduction for the project of $94 million plus carrying costs incurred from May 2017 to March 2020 for capital costs deemed not prudently incurred.
- Recently completed non-Darlington Refurbishment capex of $358 million, which exceeded the 2017–21 approved in-service capital additions, will earn an ROE at the cost of long-term debt (3.6% for the 2022 to 2026 rate period) instead of the allowed ROE until 2037.
- The OEB approved the recovery of balances as at December 31, 2019, in OPG's deferral and variance accounts. The OEB also approved a $47 million credit to customers for the impact of favourable electricity revenue during the 2020 and 2021 coronavirus pandemic response (net of any incremental pandemic-related OM&A).
- All previously existing regulatory accounts will continue, along with new accounts to track (1) any financial impact from a possible transition to and implementation of International Financial Reporting Standards from U.S. Generally Accepted Accounting Principles, (2) revenue requirement impact for a planned new corporate campus, and (3) any revenue requirement impact to nuclear liabilities and depreciation expense from accounting end-of-life assumptions for the Pickering GS.
- An earnings-sharing mechanism was also approved, where regulated earnings 100 basis points above the approved ROE over the cumulative five-year term will be shared 50/50 with customers.

Approved Regulated Nuclear Amounts	2022	2023	2024	2025	2026
Nuclear revenue requirement (CAD millions)	3,515.5	3,430.0	3,518.3	3,197.6	2,439.5
Nuclear rate base (CAD millions)	8,600.3	8,615.0	11,033.4	12,188.8	12,991.8
Nuclear payment amount (CAD per MW hour (MWh))	105.22	109.04	104.63	108.19	118.91
Hydro payment amount (CAD per MWh)	44.91	44.91	44.91	44.57	44.57

- In June 2023, OPG filed an application with the CNSC to extend operating Pickering GS to September 2026.
    - In December 2022, the Province amended O. Reg. 53/05 to require OPG to establish a variance account to track the additional revenues and costs associated with operating Units 5 to 8 of the Pickering GS between January 1 and September 30, 2026. The disposition of the account balance will be subject to the OEB's prudence review and approval in a future proceeding.
- On April 4, 2025, the CNSC granted OPG a licence to construct a BWRX-300 SMR at the Darlington New Nuclear Project (DNNP) site. This marks the first licence issued for the construction of a grid-scale SMR in Canada. The 10-year licence is valid until March 31, 2035, and includes conditions for oversight and compliance. The decision followed a two-step public hearing in 2024–25 and reflects the CNSC's conclusion that OPG can construct the SMR safely.

Assessment of Regulatory Framework

Criteria	Score	Analysis
1. Deemed Equity	Excellent	The OEB allows OPG to have a deemed equity of 45%.
	Good	
	Satisfactory	
	Below Average	
	Poor	
2. Allowed ROE	Excellent	OPG has an allowed ROE of 8.66% for 2022–26 (based on nuclear regulated rates), which is in line with the other regulated utilities in Ontario. Any difference in ROE between the Company and other regulated utilities in the Province is mainly because of the timing of the regulatory filings and the interest rate environment prevalent at that time.
	Good	
	Satisfactory	
	Below Average	
	Poor	
3. Energy Cost Recovery	Excellent	N/A; energy costs are recovered through rates for OPG.
	Good	
	Satisfactory	
	Below Average	
	Poor	
4. Capital and Operating Cost Recovery	Excellent	Under Custom IR for the nuclear facilities, the capex program for OPG is preapproved for a five-year period by the OEB and recovered through base rates. Future test years are used for nuclear rates applications. Some volume risk exists, but this is partly mitigated by (1) use of deferral accounts for volumetric differences and (2) the fact that rates are based on forecasts that include scheduled outages. However, lost revenues resulting from forced outages beyond the forecast allowances are not recoverable through rates.
	Good	
	Satisfactory	
	Below Average	
	Poor	
5. COS versus IRM	Excellent	The nuclear facilities operate under Custom IR, which is a hybrid of COS and the IR framework, for a five-year term. We consider the Custom IR framework as reasonable.
	Good	
	Satisfactory	
	Below Average	
	Poor	
6. Political Interference	Excellent	The Government of Ontario plays a significant role in the electricity sector in Ontario, given that most of the utilities are government owned (OPG is owned by the Province). Furthermore, stakeholders, such as the IESO, are also government owned. As a result, the government has direct and indirect influence on Ontario's electricity industry as evidenced by the rate freeze on hydroelectric base rates in 2021.
	Good	
	Satisfactory	
	Below Average	
	Poor	
7. Stranded Cost Recovery	Excellent	Regulated utilities in Ontario have a limited history of stranded costs. Most prudently incurred or budgeted capex is approved by the OEB. While OPG has seen some write-downs, these have been because the OEB deemed the costs overruns to have been imprudent.
	Good	
	Satisfactory	
	Below Average	
	Poor	
8. Rate Freeze	Excellent	In November 2021, the Province amended O. Reg. 53/05 to freeze hydroelectric base rates for the Company at the 2021 level for the next regulatory period from 2022 to 2026. Rates for nuclear facilities were not frozen and have been set by the OEB. We note that the hydroelectric rate freeze may modestly pressure OPG's earnings as the Company will have to find efficiencies to offset inflation.
	Good	
	Satisfactory	
	Below Average	
	Poor	

Appendix 4—Long-term Debt and Credit Facilities

Long-term Debt

(CAD millions as at December 31, 2024)	Maturity	Amount
OEFC + Corporate Credit Facilities	2026–48	2,859
Medium Term Note Program	2025–54	5,950
UMH[1]	2041	160
PSS[2]	2067	245
LMELP[1]	2026–54	1,995
Eagle Creek[1]	2025–30	516
Other		25
Subtotal		**11,750**
Less: Bond issuance fees		(43)
Less: Current portion		(604)
Total long-term debt		**11,103**

1 Nonrecourse to OPG as debt is secured by assets of the associated project.
2 Secured by assets of the projects; recourse to OPG until the recourse release date.

- Debt at UMH, LMELP, and Eagle Creek are secured by assets of the associated project and nonrecourse to OPG. Debt at PSS is secured by assets of the project and are recourse to OPG until the recourse release date.

Maturity Profile

(CAD millions as at December 31, 2024)	2025	2026	2027	2028	2029	Thereafter	Total
Long-term debt	604	674	530	269	505	9,168	**11,750**
	5%	6%	5%	2%	4%	78%	**100%**

- OPG's maturity profile is fairly spread out.

Credit Facilities

(CAD millions as at December 31, 2024)	Maturity	Amount	Drawn/LOC	Available
Committed credit facility	May 2029	1,000	0	1,000
Committed credit facility–USD 750 million	Nov. 2025	1,079	0	1,079
OEFC general corporate credit facility	Dec. 2026	750	0	750
OFA[2] general corporate credit facility	Dec. 2029	1,250	0	1,250
Canada Infrastructure Bank term credit facility[3]	Jul. 2025	970	759	211
Short-term uncommitted credit facilities	Demand	677	430	247
Short-term uncommitted overdraft facilities	Demand	25	0	25
Lower Mattagami River Project[1]	Aug. 2028	460	60	400
UMH credit facilities[1]	Oct. 2025	16	14	2
UMH overdraft facilities[1]	Oct. 2025	8	0	8
Eagle Creek credit facility—USD 20 million[1]	Oct. 2028	29	0	29
Subtotal		**6,264**	**1,263**	**5,001**
CPs—corporate			0	0
CPs—LMELP			215	(215)
Total		**6,264**	**1,478**	**4,786**

1 Nonrecourse to OPG as debt is secured by assets of the associated project.
2 OFA: Ontario Financing Authority.
3 The facility is made available to fund part of the expenditures required to prepare for the construction of OPG's first SMR at the DNNP sites. The facility is expected to mature in July 2025.
Note: CP=commercial paper.

- OPG has a reasonable liquidity profile.
- The Company has a $1.0 billion Canadian commercial paper (CP) program (none outstanding as at December 31, 2024) and a USD 750 million CP program in the U.S. (none outstanding as at December 31, 2024). These CP programs are supported by the following facilities:
    - Committed bank facility of $1.0 billion (due date of May 2029);
    - A USD 750 million bank facility (due date of November 2025, with a one-year term-out option);
    - An OEFC facility of $750 million (due date of December 2026); and
    - An OFA facility of $1,250 million (due date of December 2029).
- The LMELP, UMH, and Eagle Creek facilities are used to support the respective projects and are nonrecourse to OPG.

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CREDIT OPINION
1 April 2022

Update

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RATINGS

Ontario Power Generation Inc.

Domicile	Ontario, Canada
Long Term Rating	A3
Type	Senior Unsecured - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Ontario Power Generation Inc.

Update to credit analysis

Summary

Ontario Power Generation's (OPG) A3 rating reflects a Baseline Credit Assessment (BCA) of Baa3 with a 3 notch uplift based on high dependence on and a high probability of extraordinary support from the Province of Ontario (Aa3 stable).

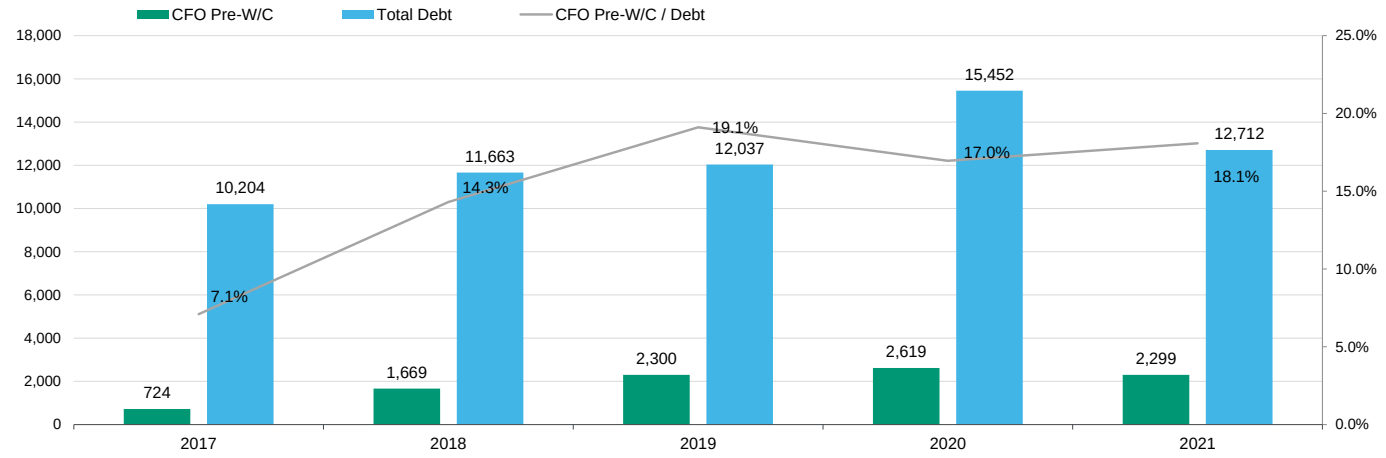
OPG's credit profile benefits from its substantial regulated nuclear and hydroelectric operations that are expected to generate the vast majority of its relatively stable cash flow. OPG's contracted assets generally benefit from long contract tenors and a strong counterparty in the Ontario Independent Electricity System Operator (IESO, Aa3 stable) to which the majority of assets are contracted and to which they pass through most of their costs. The company also has diversification benefits across its extensive fleet.

Offsetting these strengths, OPG is exposed to availability risk across its fleet of generation assets, and some hydrology risk. While small, its merchant generation segment has grown in recent years as a result of several 100% debt financed acquisitions and the potential remains for further debt financed M&A. Nonetheless, we expect the company's CFO pre-W/C to debt ratio to be sustained in the 13-17% range. The company is also pursuing a CAD12.8 billion nuclear refurbishment project across 4 units at its Darlington nuclear generation station that carries a very high level of execution risk.

OPG is 100% owned by the Province of Ontario and is considered a government related issuer (GRI) under our GRI methodology. The three notch uplift attributed to OPG as a GRI incorporates our expectation of an enduring link between OPG and the Province. Our high support assumption considers that OPG produces more than half of the power generated in the Province at a comparatively low cost, making its infrastructure essential to the Ontario economy. OPG also implements government policy, its board is appointed by the Province and the Ontario Electricity Financial Corporation (OEFC, Aa3 stable), a crown corporation, is a source of debt capital for OPG. Our assessment of high default dependence reflects that both OPG and the Province largely rely on the same revenue base and share some political risks.

Exhibit 1

Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt (CAD MM)



Source: Moody's Financial Metrics

Credit strengths

» Primarily regulated generation facilities support stable cash flow generation

» Non-regulated generation segment dominated by long term contracts

» Our expectation of support from the Province of Ontario given its 100% ownership

» Diversification benefits by generating station and unit, and fuel source

Credit challenges

» CAD12.8 billion nuclear refurbishment project underway has a very high level of execution risk

» Financial metrics pressured by several debt financed acquisitions with the potential for further debt financed M&A

» Small but growing merchant cash flow entails more risk

» Availability risk across the fleet, including low levels of hydrology risk

Rating outlook

The stable outlook incorporates the following expectations:

» The company continues to execute the Darlington nuclear refurbishment on time and budget

» CFO pre-WC/debt is in the 13-17% range

» The relationship with the Province remains stable and supportive

Factors that could lead to an upgrade

» A material increase in financial metrics such that CFO pre-WC/debt is sustained above 20%

» An improvement in regulatory outcomes or business risk profile

» An upgrade of the Province

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the ratings tab on the issuer/entity page on www.moodys.com for the most updated credit rating action information and rating history.

Factors that could lead to a downgrade

» Challenges or delays executing the Darlington nuclear refurbishment

» A weakening of the business risk profile by, for example, further growing the merchant segment

» A reduction in the probability of support from the Province

» A deterioration in financial metrics such that CFO pre-WC/debt is forecast to fall below 12% on a sustained basis

Key indicators

Exhibit 2

Ontario Power Generation Inc. [1]

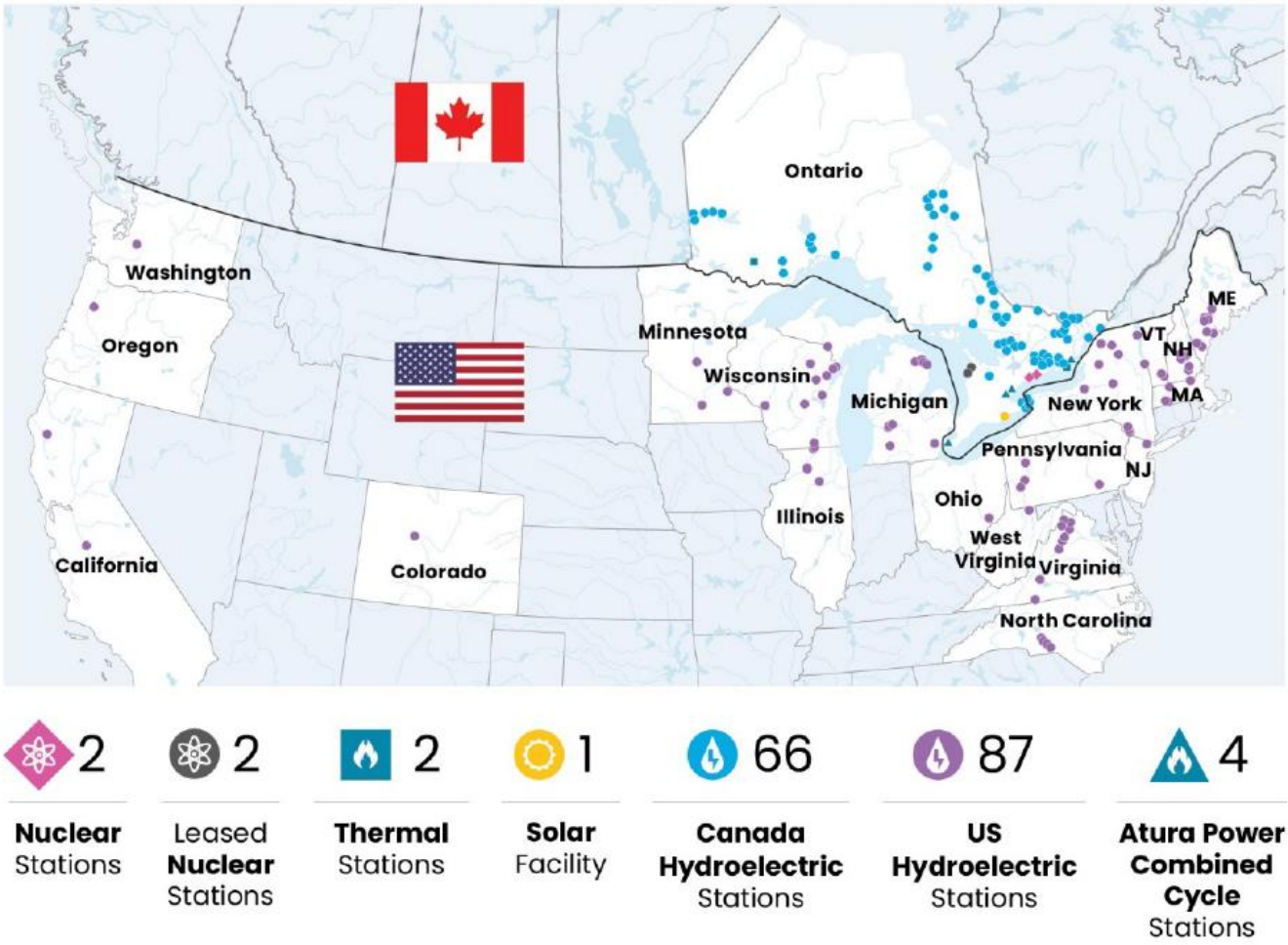
	Dec-17	Dec-18	Dec-19	Dec-20	Dec-21
CFO Pre-W/C + Interest / Interest	2.8x	4.7x	6.0x	6.1x	5.8x
CFO Pre-W/C / Debt	7.1%	14.3%	19.1%	17.0%	18.1%
CFO Pre-W/C – Dividends / Debt	7.0%	11.7%	19.0%	16.8%	17.9%
Debt / Capitalization	44.7%	45.6%	44.2%	47.9%	40.7%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics

Profile

Headquartered in Toronto, Ontario, OPG is an electricity generation company wholly owned by the Province with an in-service generating capacity of 18,958 MW at December 31, 2021. OPG owns and operates 75 generating stations, 2 of which are nuclear, 66 hydroelectric, 2 thermal, 1 solar and 4 combined-cycle natural gas-fired plants in Ontario, Canada. In the US, OPG also wholly or jointly owns and operates 87 hydroelectric stations and has interests in 14 other hydroelectric and 2 solar facilities. OPG's nuclear and most of its hydroelectric facilities are regulated by the Ontario Energy Board (OEB).

Exhibit 3
OPG's service territory



Source: OPG December 31, 2021

Detailed credit considerations

Primarily regulated and contracted assets generate predictable cash flow

OPG's strong business risk profile is driven by its high proportion of regulated and contracted cash flow. Regulated earnings from OEB rate regulated assets accounted for 73% of EBITDA from its generating business segments in 2021, including 42% from the regulated nuclear generation segment and 31% from the regulated hydroelectric generation segment. The Atura Power combined cycle plants generated 14% of EBITDA and contracted hydro electric and other, which has more contracted cash flow than merchant, generated 13% of EBITDA. The company has extensive diversity by generation station and unit within each segment that reduces volatility. It also has some hydrology risk, albeit low, and negligible levels of commodity price risk, a key credit positive. Unlike most other regulated utilities, OPG owns generating assets only and does not have any lower risk transmission and distribution assets. As a result, as a higher risk generation company, OPG is exposed to availability risks on all of its assets.

The company's regulated assets should provide predictable cash flow going forward. A multiyear rate plan that is in place from 2022-2026 establishes volumetric prices for the regulated nuclear segment and a change in regulations provides pricing for regulated hydroelectric assets over this period.

The nuclear generation segment benefits from diversification across 2 nuclear generating stations, with 6 and 4 operating reactors respectively, that enable the company to maintain high levels of generation and cash flow while undertaking nuclear refurbishment.

The permanent shutdown of the Pickering nuclear generating station units in 2024 and 2025 will reduce diversity and, with fewer operating nuclear units, heighten the impact of any unplanned outages. Offsetting this, following refurbishment Darlington should experience fewer outages.

In the second half of 2021, OPG reached a settlement with its intervenors that was subsequently approved by the OEB. The settlement led to a 2022-2026 nuclear generation revenue requirement of CAD16 billion, compared to CAD16.7 billion in the company's rate case application. Regulated prices are designed to support an allowed level of operating costs and earn a return on its capital costs for a forecast amount of generation. Significantly, the settlement supports growth in rate base over the period as the company continues to make progress on the Darlington refurbishment.

Nuclear rate base is allowed an ROE of 8.66% and hydroelectric 9.33% and both have equity capital of 45%. Performance that deviates by more than 300 bps in any given year may lead to a regulatory review. Rate case lag considerably improved with the most recent rate case where a payments order was issued in January 2022 with new rates effective that month, although the extensive use of deferral accounts which reduces cash flow is a credit negative. Rates have significantly increased over the past several years. As recently as the first half of 2017 rates were CAD 59.29 MWh, a price that, like the table below, incorporates rates riders and variance accounts.

Exhibit 4

	2022	2023	2024	2025	2026
Regulated Nuclear Generation Total price ($/MWh)	105.22	109.04	104.63	108.19	118.91
Approved Nuclear Rate Base (CAD million)	8,600	8,615	11,033	12,188	12,992
Forecast Nuclear Production (TWh)	33.6	31.2	34	31.1	21.9
Regulated Hydroelectric Generation price ($/MWh)	44.91	44.91	44.91	44.57	44.57

Source: OPG December 31, 2021

The settlement left open 3 issues that were addressed in a subsequent decision from the OEB.

First, the OEB has determined that small modular reactor related costs may be recorded in a nuclear development variance account (NDVA). Subsequent to this decision, in December 2021, OPG announced a partnership with GE Hitachi nuclear energy with the goal of deploying Canada's first small modular reactor, a 300MW design, as early as 2028. The NDVA, which does not have a limit but is subject to prudence review, had a balance of CAD122 million at FYE 2021. The company has not incorporated any spending into its 2022-2026 rate case application. With significant spending likely and no timelines for recovery of the balance or cash recovery of carrying costs, the burden on the company's balance sheet is likely to grow over time.

Second, the OEB completed a prudence review on the Darlington heavy water storage and drum handling facility (D2O) project costs. The OEB approved rate base for the project was lower than the project costs, leading to a charge to earnings of CAD111 million in Q4 2021. Initial estimates for the D2O project in June of 2012 were CAD108 million compared to an estimate of close to CAD400 million that was incorporated into the CAD12.8 billion figure and final costs of about CAD510 million. We view cost disallowances as a credit negative, although in the context of the overall refurbishment project and the company, they are not material given overall refurbishment project execution risk.

Finally, the company's rate smoothing deferral account (RSDA) will grow at CAD83 million over the period 2022-2026, down from the CAD760 million reflected in the company's rate case application. We continue to view OPG's rate smoothing as a credit negative, however the lower amount deferred in the period will reduce the amount of pressure that rate smoothing would have otherwise placed on financial metrics. The CAD83 million will be added to the 31 December 2021 balance of CAD531 million. While the company recognizes the revenue in the period earned, it does not recover cash from ratepayers. These amounts will be financed at the company's long term debt rate which will be added to the RSDA balance. The balance will be recovered over a period not to exceed 10 years following the completion of the Darlington refurbishment project.

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 may be challenging for OPG to earn its allowed returns over the period given ongoing investments in rate base assets during the period that exceed depreciation.

Mitigating this challenge is the increase in production that will directly result from some of these investments. Regulated prices for the period 1 June 2017 to 31 December 2021 were calculated annually using a base regulated price escalated with an OEB approved formula for inflation less a 0% productivity factor adjustment and a -0.3% stretch factor adjustment.

The contracted hydroelectric and other generation segment consists of lower risk contracted assets in Ontario and higher risk, primarily merchant US based assets. Ontario based assets are all under contract on generally favorable terms and almost all of the contracts are with the IESO. The largest of these is the project financed Lower Mattagami Energy Limited Partnership (A1 stable). It, and other contracted hydro facilities like it, including UMH Energy Partnership (A2 stable), have strong contract terms which include limited hydrology risk and contract expiries over the period 2059-2067. The two Ontario thermal plants in this segment have substantial capacity, but are largely peaking facilities and have low levels of generation. They are primarily compensated based on their availability and have cost pass through provisions, however they have shorter contract tenors compared to the contracted hydro facilities. The US assets, which consist of Eagle Creek and the acquisition of Cube Hydro that closed October 2019, have some contracts, but are primarily merchant assets with substantially more risk than the rest of the portfolio. OPG has grown its US presence and its Atura business segment through acquisitions in the past few years.

Exhibit 5
OPG acquired assets

Asset acquired	Capacity (MW)	Fuel feedstock	Announcement date	Closing date	Enterprise value (CAD billion)	Acquisition Price (CAD billion)	Assumed debt (CAD billion)
Ontario CCGT	1858	Natural Gas	30-Jul-19	29-Apr-20	2.8	2.8	0
Cube Hydro	385	Hydro	25-Jun-19	7-Oct-19	1.5	1.1	0.4
Eagle Creek	226(1)	76 hydro 2 solar plants	9-Aug-18	27-Nov-18	0.7	0.4	0.3

[1] 226MW at FYE 2018.
Source: Company filings

The Atura Power business consists of 4 combined cycle gas plants that operate under contract with the IESO or other long term contracts on similar terms to the above mentioned thermal plants. The longest of the contracts is the 900MW Napanee plant that operates under a 20 year contract that expires in 2040.

Darlington nuclear refurbishment carries a very high level of execution risk

Weighing on the company's' business risk profile is the ongoing nuclear refurbishment at the Darlington Generation Station, which is forecast to cost CAD12.8 billion and take about a decade to refurbish all 4 units. The first refurbished unit returned to service in June of 2020. While the refurbishment of the first unit was a few months behind schedule, management believes that the overall cost and schedule to complete all 4 units remains on target with a modest Covid pandemic driven delay. The start of the unit 3 refurbishment was pushed back 3-4 months as a result of Covid and all subsequent refurbishments will likely be similarly delayed. The delay in the start to the refurbishment of Unit 3 led to higher generation levels than previously anticipated in 2020, driving increased cash flow in that year. The regulatory framework continues to incorporate the forecasted capex to bring the units in service, so it is already reflected in both rate base and revenues without the need for OPG to file a rate case.

Exhibit 6
Darlington refurbishment timeline

Darlington	Capacity	Refurbishment start date	Refurbishment completion date
Unit 2	878	Oct-16	Jun-20
Unit 3	878	Sep-20	Q1-2024
Unit 1	878	Q1-2022	Q2-2025
Unit 4	878	Q3-2023	Q4-2026

Source: Company filings

Financial metrics to remain reasonably predictable

We expect CFO pre-WC/debt to be in the range of 13-17% over the next few years with cash flow to remain reasonably predictable and generation levels driving some variability. The variability in generation leads to a wider range in forecast financial metrics compared to transmission and distribution companies. Collectively, the acquisitions reflect an enterprise value of about CAD5 billion that has contributed to the increase in debt financing on the company's balance sheet in recent years. Pension adjustments for OPG and many peers have been volatile in the past few years and OPG's pension adjustment declined by about CAD2 billion to CAD2.9 billion at FYE 2021 from CAD5 billion at FYE 2020. We expect internally generated cash flow and some modest debt issuances to fund the capital program, of which about half is focused on the Darlington refurbishment. The company has credit friendly financial policies and OPG seldom pays dividends with the only dividends in recent years paid connected to asset sales (property sales, not generation facilities) that it was directed to make by the Ontario government.

Further debt financed M&A remains a risk, although management has indicated that they plan to focus on their existing assets. We believe that any further acquisitions or investments will likely be small and similar to the 48MW Racine Hydroelectric generation facility that OPG acquired for CAD112 million on 30 December 2021

There is some structural subordination stemming from project finance debt at Canadian contracted assets totaling about CAD2.2 billion at FYE 2021 and about CAD500 million of debt on US assets. However, unlike the vast majority of regulated utilities, there is no debt outstanding at the regulated businesses that generated about 70% of EBITDA in 2021. That, in conjunction with primarily centralized funding for OPG, results in no notching for structural subordination. As of Q2 2019, OPG no longer consolidates Fair Hydro Trust, leading to a reduction in consolidated debt of CAD900 million.

High probability of support from the Province provides an uplift to OPG's credit profile

Given the 100% ownership interest held by the Province, OPG is considered a government related issuer (GRI) under our GRI methodology. Based on our estimate of a high probability of extraordinary support in case of financial distress, the A3 credit profile incorporates 3 notches of uplift from OPG's BCA of baa3.

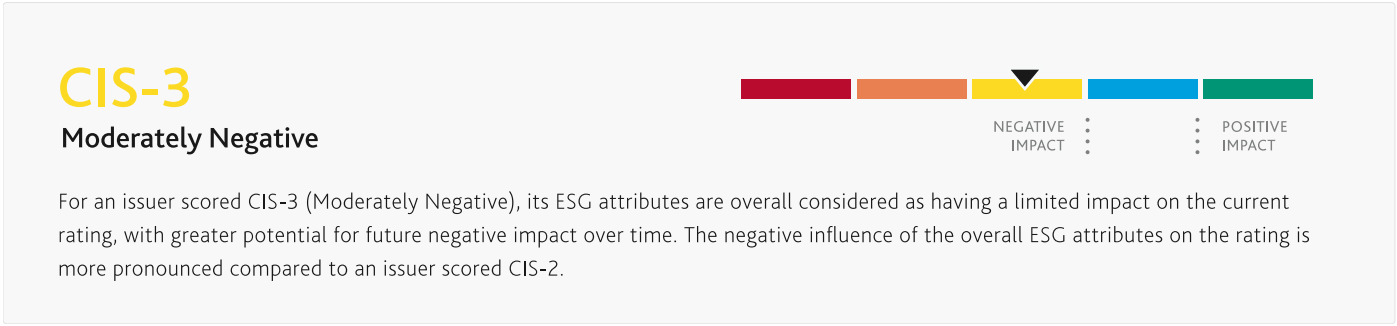
The company's ratings incorporate our expectation that extraordinary financial support to OPG would be forthcoming from the Province if needed. Our high support assumption considers that OPG produces more than half of the power in the Province at a comparatively low cost, making its infrastructure essential to the Ontario economy. OPG also implements government policy which can have negative credit implications. For example, in an effort to reduce and smooth rate increases for customers, Ontario Regulation 53/05 mandated the creation of the RSDA, including the financing of the RSDA at the long term debt rate and recovery over a 10 year period after the Darlington refurbishment is complete. The Province also appoints OPG's board, concurs its business plans and is a source of debt financing through the OEFC. We do not believe there are any barriers that would prevent the Province from providing timely support.

Our assessment of high default dependence reflects that both OPG and the Province largely rely on the same revenue base and share some political risks. While the OEFC is a source of financing, OPG has been increasing the level of its borrowing from public debt capital markets.

ESG considerations

OPG's ESG Credit Impact Score is CIS-3 (Moderately Negative).

Exhibit 7
ESG Credit Impact Score



Source: Moody's Investors Service

OPG's ESG Credit Impact Score is moderately negative (**CIS-3**) reflecting high social risk along with moderately negative environmental and governance risk.

Exhibit 8
ESG Issuer Profile Scores



Source: Moody's Investors Service

Environmental

We assess the company's exposure to environmental risks as moderately negative (**E-3** issuer profile score) driven by moderately negative exposure to physical climate risks mostly due to its exposure to extreme weather patterns which is a challenge for the sector. OPG's nuclear generation assets are moderately negative for waste management and pollution risks. While the company has not had any problems with its nuclear fleet or nuclear waste, it remains an inherent risk for nuclear operators. These risks are offset by low to neutral exposure to carbon transition risk owing to its portfolio of primarily nuclear and renewable assets and neutral to low exposure to water management and natural capital risks.

Social

Exposure to social risks is highly negative (**S-4** issuer profile score) reflecting the highly negative exposure to demographics and societal trends associated with rate pressures as evidenced by some very lengthy delays associated with recovering some costs. Factors contributing to rate pressures include more expensive sources of energy in the Province, particularly some high priced renewables. Moderately negative exposure to responsible production is a result of the risk to public safety posed by nuclear generation facilities including those owned and operated by OPG.

Governance

The influence of governance is low to neutral (**G-2** issuer profile score) and is broadly in line with other utilities. The company is effectively controlled by the Province, its sole owner, which is reflected in its moderately negative exposure to Board Structures, Policies, & Procedures. This is offset by stable financial policies and a track record that includes for example very limited dividends that provides financial flexibility for the company.

ESG Issuer Profile Scores and Credit Impact Scores for OPG are available on Moodys.com. In order to view the latest scores, please click here to go to the landing for OPG on MDC and view the ESG Scores section.

Liquidity analysis

OPG has an adequate liquidity profile driven by about CAD3.1 billion (around CAD2.4 billion available as of 31 December 2021) of credit facilities and expected cash flow that together are sufficient to cover its uses for the next 12 months.

As of December 2021, OPG has a CAD1 billion committed credit facility of which matures in May of 2026. OPG also has a USD750 million 364 day revolving committed facility that expires in November of 2022 with a one year term out provision at the company's option. Both of these facilities backstop CAD1 billion andUSD750 million commercial paper programs that had CAD57 million outstanding at December 2021. Also included in the CAD3.1 billion, the company has a CAD750 million committed credit facility with the OEFC with a maturity date of December 2026. Lastly, the company has a CAD400 million committed facility at Lower Mattagami Energy Limited Partnership and a USD25 million committed facility at OPG Eagle Creek Holdings LLC and subsidiaries. Drawings were primarily used for letters of credit.

Moody's forecasts cash flow from operations of around CAD2 billion in the next twelve months, in addition to the available credit facilities and cash and cash equivalents of CAD698 million as of 31 December 2021, to be sufficient to cover the uses comprising around CAD3 billion of expected capital expenditures and around CAD361 million of debt maturities in the next 12 months. We expect OPG will rely in part on debt to finance its ongoing capex and refinance its upcoming debt maturities. The company's liquidity position benefits from the lack of regular dividends payable to the Province.

There are material adverse change clauses in its credit facilities that could prevent borrowings under certain circumstances, a credit and liquidity negative. Moody's expects the company to manage its program maturities, cash on hand and its swing lines in a prudent fashion.

Rating methodology and scorecard factors

Exhibit 9
Methodology Scorecard Factors
Ontario Power Generation Inc.

Regulated Electric and Gas Utilities Industry Scorecard [1][2]	Current FY 12/31/2021		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	Baa	Baa	Baa	Baa
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Baa	Baa	Baa	Baa
b) Sufficiency of Rates and Returns	Ba	Ba	Ba	Ba
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	A	A	A	A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.0x	A	5x - 6x	A
b) CFO pre-WC / Debt (3 Year Avg)	18.0%	Baa	13% - 17%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	17.8%	A	13% - 17%	Baa
d) Debt / Capitalization (3 Year Avg)	44.3%	A	38% - 43%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		Baa1		Baa1
HoldCo Structural Subordination Notching		0		0
a) Scorecard-Indicated Outcome		Baa1		Baa1
b) Actual Rating Assigned		A3		A3

Government-Related Issuer	**Factor**
a) Baseline Credit Assessment	Baa3
b) Government Local Currency Rating	Aa3
c) Default Dependence	High
d) Support	High
e) Actual Rating Assigned	A3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 12/31/2021(L);
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics™

Appendix

Exhibit 10

Cash Flow and Credit Metrics (CAD MM) [1]

CF Metrics	Dec-17	Dec-18	Dec-19	Dec-20	Dec-21
As Adjusted					
FFO	**1,044**	**1,482**	**1,828**	**2,538**	**2,231**
+/- Other	-320	187	472	81	68
CFO Pre-WC	**724**	**1,669**	**2,300**	**2,619**	**2,299**
+/- ΔWC	80	-160	99	103	59
CFO	**804**	**1,509**	**2,399**	**2,722**	**2,358**
- Div	15	301	17	19	19
- Capex	1,713	1,648	1,851	1,663	1,943
FCF	**-924**	**-440**	**531**	**1,040**	**396**
(CFO Pre-W/C) / Debt	7.1%	14.3%	19.1%	17.0%	18.1%
(CFO Pre-W/C - Dividends) / Debt	7.0%	11.7%	19.0%	16.8%	17.9%
FFO / Debt	10.2%	12.7%	15.2%	16.4%	17.6%
RCF / Debt	10.1%	10.1%	15.0%	16.3%	17.4%
Revenue	5,158	5,537	6,022	7,240	6,877
Interest Expense	404	446	462	514	479
Net Income	403	270	758	1,074	1,050
Total Assets	48,831	52,134	55,183	61,961	61,071
Total Liabilities	37,233	39,399	41,286	46,694	44,352
Total Equity	11,598	12,735	13,897	15,267	16,719

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months
Source: Moody's Financial Metrics

Exhibit 11

Ontario Power Generation Inc. Moody's - Adjusted Debt Breakdown (CAD MM)

(CAN Millions)	FYE Dec-16	FYE Dec-17	FYE Dec-18	FYE Dec-19	FYE Dec-20	FYE Dec-21
As Reported Debt	**5,522.0**	**6,579.0**	**7,878.0**	**8,390.0**	**10,382.0**	**9,848.0**
Pensions	3,029.0	3,437.0	3,656.0	3,585.0	5,023.0	2,864.0
Operating Leases	184.4	171.3	72.5	55.0	47.0	0.0
Non-Standard Adjustments	14.0	17.0	56.0	7.0	0.0	0.0
Moody's Ajusted Debt	**8,749.4**	**10,204.3**	**11,662.5**	**12,037.0**	**15,452.0**	**12,712.0**

Based on consolidated financial data of Ontario Power Generation Inc. All figures are calculated using Moody's estimates and standard adjustments
Source: Moody's Financial Metrics

Exhibit 12

Peer Comparison Table (USD MM) [1]

	Ontario Power Generation Inc. A3 (Stable)			Public Service Enterprise Group Incorporated Baa2 (Stable)			NextEra Energy, Inc. (P)Baa1 (Stable)			Exelon Corporation Baa2 (Stable)		
(In US millions)	FYE Dec-19	FYE Dec-20	FYE Dec-21	FYE Dec-19	FYE Dec-20	FYE Dec-21	FYE Dec-19	FYE Dec-20	FYE Dec-21	FYE Dec-20	FYE Dec-20	FYE Dec-21
Revenue	4,538	5,403	5,486	10,076	9,603	9,722	19,204	17,997	17,069	34,438	33,039	36,347
CFO Pre-W/C	1,733	1,955	1,834	3,079	2,951	2,856	7,938	8,494	8,479	8,176	7,285	3,502
Total Debt	9,282	12,129	10,064	17,416	18,486	19,822	42,303	47,833	54,651	42,843	44,898	46,241
CFO Pre-W/C + Interest / Interest	6.0x	6.1x	5.8x	5.7x	5.4x	5.6x	4.4x	5.1x	7.1x	5.5x	5.0x	3.0x
CFO Pre-W/C / Debt	19.1%	17.0%	18.1%	17.7%	16.0%	14.4%	18.8%	17.8%	15.5%	19.1%	16.2%	7.6%
CFO Pre-W/C – Dividends / Debt	19.0%	16.8%	17.9%	12.2%	10.6%	9.2%	12.9%	11.9%	9.9%	15.8%	12.9%	4.3%
Debt / Capitalization	44.2%	47.9%	40.7%	45.1%	45.2%	49.6%	45.4%	47.1%	49.9%	47.7%	48.2%	48.4%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade
Source: Moody's Financial Metrics

Ratings

Exhibit 13

Category	Moody's Rating
ONTARIO POWER GENERATION INC.	
Outlook	Stable
Senior Unsecured -Dom Curr	A3
Commercial Paper	P-2

Source: Moody's Investors Service

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CREDIT OPINION
12 June 2023

Update

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RATINGS

Ontario Power Generation Inc.

Domicile	Ontario, Canada
Long Term Rating	A3
Type	Senior Unsecured - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Ontario Power Generation Inc.

Update to credit analysis

Summary

Ontario Power Generation's (OPG) A3 rating reflects a Baseline Credit Assessment (BCA) of baa3 with a 3 notch uplift based on its high dependence on and a high probability of extraordinary support from the Province of Ontario (Aa3 positive).

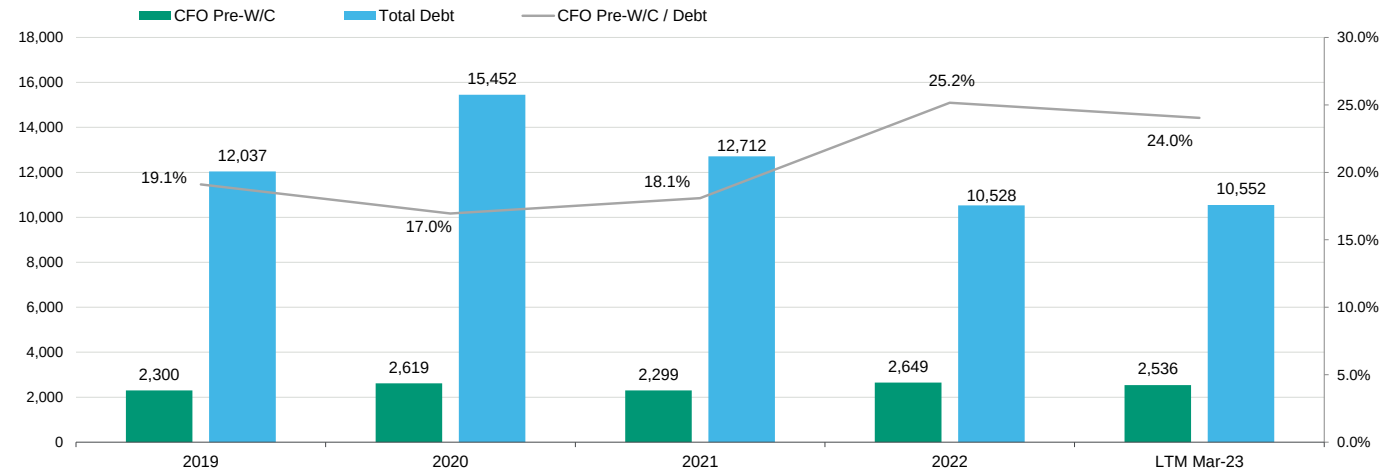
OPG's credit profile benefits from its substantial regulated nuclear and hydroelectric operations that are expected to generate the vast majority of its relatively stable cash flow. OPG's contracted assets generally benefit from long contract tenors and a strong counterparty in the Ontario Independent Electricity System Operator (IESO, Aa3 positive) to which the majority of assets are contracted and to which they pass through most of their costs. The company also has diversification benefits across its extensive fleet.

Offsetting these strengths, OPG is exposed to availability risk across its fleet of generation assets, and some hydrology risk. While small, its merchant generation segment has grown as a result of several 100% debt financed acquisitions and the potential remains for further debt financed M&A. Nonetheless, we expect the company's CFO pre-W/C to debt ratio to be sustained in the 20-25% range. The company is pursuing a CAD12.8 billion nuclear refurbishment project across 4 units at its Darlington nuclear generation station that carries a high level of execution risk. The company is also moving forward with a small modular reactor (SMR) at Darlington which carries significant execution risk. OPG expects to complete construction of the SMR in 2028.

OPG is 100% owned by the Province of Ontario and is considered a government related issuer (GRI) under our GRI methodology. The three notch uplift attributed to OPG as a GRI incorporates our expectation of an enduring link between OPG and the Province. Our high support assumption considers that OPG produces more than half of the power generated in the Province at a comparatively low cost, making its infrastructure essential to the Ontario economy. OPG also implements government policy, its board is appointed by the Province and the Ontario Electricity Financial Corporation (OEFC, Aa3 positive), a crown corporation, is a source of debt capital for OPG. Our assessment of high dependence reflects that both OPG and the Province largely rely on the same revenue base and share some political risks.

Exhibit 1

Historical CFO Pre-WC, Total Debt and CFO Pre-WC to Debt (CAD MM)



Source: Moody's Financial Metrics™

Credit strengths

» Primarily regulated generation facilities support stable cash flow generation

» Non-regulated generation segment dominated by long term contracts

» Our expectation of support from the Province of Ontario given its 100% ownership

» Diversification benefits by generating station and unit, and fuel source

Credit challenges

» CAD12.8 billion nuclear refurbishment and planned construction of an SMR have significant execution risk

» Merchant cash flow entails more risk

» Availability risk across the fleet, including low levels of hydrology risk

Rating outlook

The stable outlook incorporates the following expectations:

» The company will continue to execute the Darlington nuclear refurbishment on time and budget

» CFO pre-WC/debt in the 20-25% range

» The relationship with the Province remains stable and supportive

Factors that could lead to an upgrade

» The company is successful in its Darlington nuclear refurbishment and in largely mitigating the risks with the construction of (SMR) given the very high levels of execution risk.

» CFO pre-W/C/debt sustained above 20%

» An improvement in regulatory outcomes or business risk profile

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the issuer/deal page on https://ratings.moodys.com for the most updated credit rating action information and rating history.

» An upgrade of the Province to Aa1

Factors that could lead to a downgrade

» Challenges or delays executing the nuclear refurbishment or with the construction of the planned SMR

» A weakening of the business risk profile by, for example, further growing the merchant segment

» A reduction in the probability of support from the Province

» A deterioration in financial metrics such that CFO pre-WC/debt is forecast to fall below 12% on a sustained basis

Key indicators

Exhibit 2

Ontario Power Generation Inc. [1]

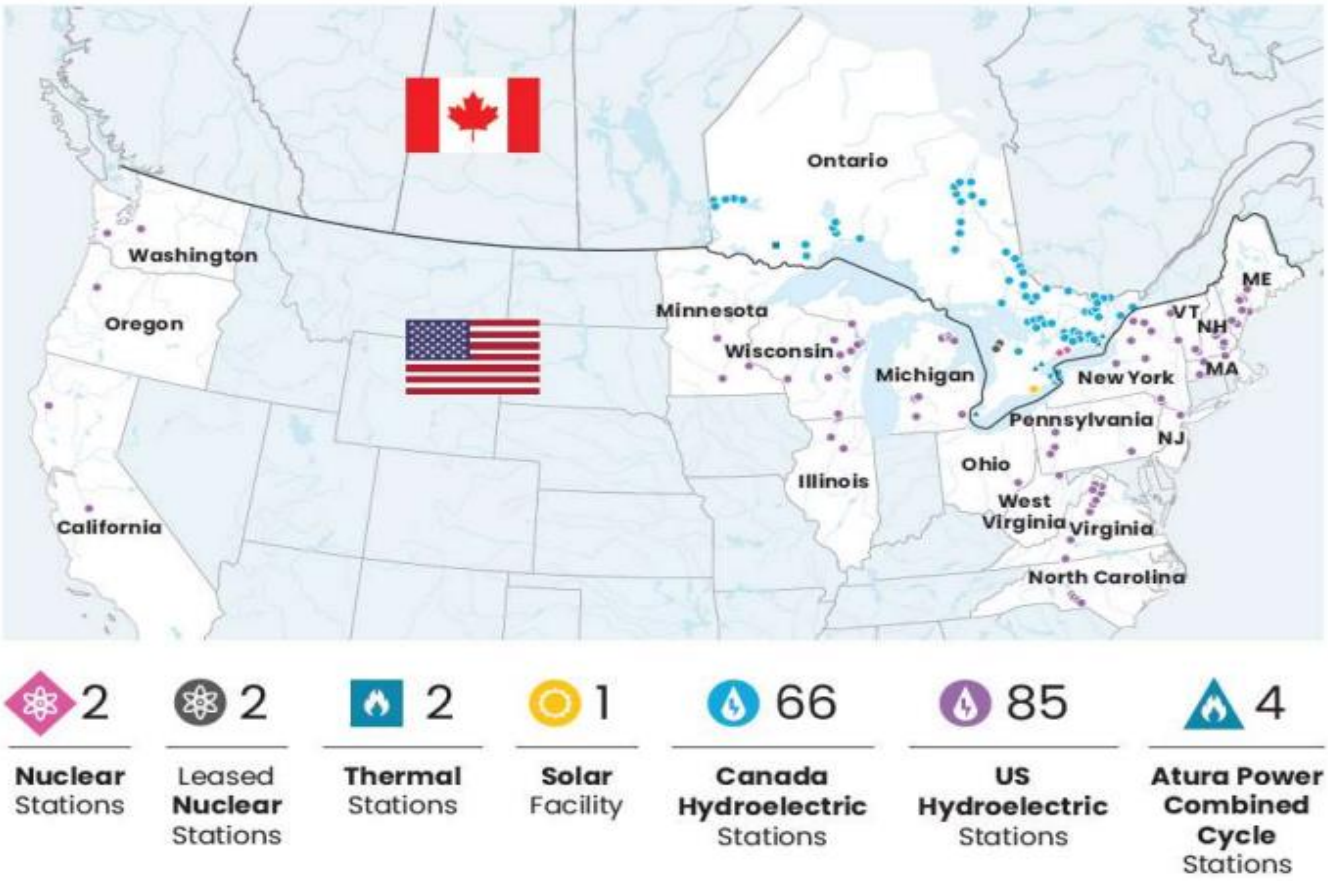
	Dec-19	Dec-20	Dec-21	Dec-22	LTM Mar-23
CFO Pre-W/C + Interest / Interest	6.0x	6.1x	5.8x	6.5x	6.6x
CFO Pre-W/C / Debt	19.1%	17.0%	18.1%	25.2%	24.0%
CFO Pre-W/C – Dividends / Debt	19.0%	16.8%	17.9%	25.0%	23.9%
Debt / Capitalization	44.2%	47.9%	40.7%	33.6%	33.2%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics™

Profile

Headquartered in Toronto, Ontario, OPG is an electricity generation company wholly owned by the Province with an in-service generating capacity of 18,225 MW at December 31, 2022. OPG owns and operates 75 generating stations, 2 of which are nuclear, 66 hydroelectric, 2 thermal, 1 solar and 4 combined-cycle natural gas-fired plants in Ontario, Canada. In the US, OPG also wholly or jointly owns and operates 85 hydroelectric stations and has interests in 14 other hydroelectric and 2 solar facilities. OPG's nuclear and most of its hydroelectric facilities are regulated by the Ontario Energy Board (OEB).

Exhibit 3
OPG's service territory



Source: OPG December 31, 2022

Detailed credit considerations

Primarily regulated and contracted assets generate predictable cash flow

OPG's strong business risk profile is driven by its high proportion of regulated and contracted cash flow. Regulated earnings from OEB's rate regulated assets accounted for 73% of EBITDA (all figures rounded) from its generating business segments in 2022, including 45% from the regulated nuclear generation segment and 27% from the regulated hydroelectric generation segment. The Atura Power combined cycle plants generated 13% of EBITDA and contracted hydro electric and other, which has more contracted cash flow than merchant, generated 14% of EBITDA. The company has extensive diversity by generation station and unit within each segment, reducing volatility. It also has some hydrology risk, albeit low, and negligible levels of commodity price risk, a key credit positive. Unlike most other regulated utilities, OPG owns generating assets only and does not have any lower risk transmission and distribution assets. As a result, as a higher risk generation company, OPG is exposed to availability risks on all of its assets.

The company's regulated assets should provide predictable cash flow going forward. A multiyear rate plan that is in place from 2022-2026 establishes volumetric prices for the regulated nuclear segment and a change in regulations provides pricing for regulated hydroelectric assets over this period.

The nuclear generation segment benefits from diversification across 2 nuclear generating stations, with 6 and 4 operating reactors respectively, that enable the company to maintain high levels of generation and cash flow while undertaking nuclear refurbishment. In response to a Provincial request, OPG is updating a feasibility assessment for the refurbishment of Pickering Units 5 to 8. The Pickering units are currently scheduled to be shutdown in the next few years.

In the second half of 2021, OPG reached a settlement with its intervenors that was subsequently approved by the OEB. The settlement led to a 2022-2026 nuclear generation revenue requirement of CAD16 billion, compared to CAD16.7 billion in the company's rate case application. Regulated prices are designed to support an allowed level of operating costs and earn a return on its capital costs for a forecast amount of generation. Significantly, the settlement supports growth in rate base over the period as the company continues to make progress on the Darlington refurbishment.

Nuclear rate base is allowed an ROE of 8.66% and hydroelectric 9.33% and both have equity capital of 45%. Performance that deviates by more than 300 bps in any given year may lead to a regulatory review. Rate case lag has improved considerably with the most recent rate case, where a payments order was issued in January 2022 with new rates effective that month, although the extensive use of deferral accounts that reduce cash flow is a credit negative. Rates have significantly increased over the past several years. As recently as the first half of 2017 rates were CAD 59.29 MWh, a price that, like the table below, incorporates rates riders and variance accounts.

Exhibit 4

	2023	2024	2025	2026
Regulated Nuclear Generation Total price ($/MWh)	109.04	104.63	108.19	118.91
Approved Nuclear Rate Base (CAD million)	8,615	11,033	12,188	12,992
Forecast Nuclear Production (TWh)	31.2	34.0	31.1	21.9
Regulated Hydroelectric Generation price ($/MWh)	44.91	44.91	44.57	44.57

Source: OPG December 31, 2022

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 may be challenging for OPG to earn its allowed returns over the period given ongoing investments in rate base assets during the period that exceed depreciation. Mitigating this challenge is the increase in production that will directly result from some of these investments. Regulated hydroelectric prices for the period 1 June 2017 to 31 December 2021 were calculated annually using a base regulated price escalated with an OEB approved formula for inflation less a 0% productivity factor adjustment and a -0.3% stretch factor adjustment.

The contracted hydroelectric and other generation segment consists of lower risk contracted assets in Ontario and higher risk, primarily merchant US based assets. Ontario based assets are all under contract on generally favorable terms and almost all of the contracts are with the IESO. The largest of these is the project financed Lower Mattagami Energy Limited Partnership (A1 stable). It, and other contracted hydro facilities like it, including UMH Energy Partnership (A2 stable), have strong contract terms which include limited hydrology risk and contract expiries over the period 2059-2067. The two Ontario thermal plants in this segment have substantial capacity, but are largely peaking facilities and typically have low levels of generation. They are primarily compensated based on their availability and have cost pass through provisions, however they have shorter contract tenors compared to the contracted hydro facilities. The US assets have some contracts, but are primarily merchant assets with substantially more risk than the rest of the portfolio. OPG has grown its US presence and its Atura business segment through acquisitions in the past few years.

The Atura Power business consists of 4 combined cycle gas plants that operate under contract with the IESO or other long term contracts on similar terms to the above mentioned thermal plants. The longest of the contracts is the 900 MW Napanee plant that operates under a 20 year contract that expires in 2040.

Darlington nuclear refurbishment and SMR construction have significant execution risk

Weighing on the company's business risk profile is the ongoing nuclear refurbishment at the Darlington Generation Station, which is forecast to cost CAD12.8 billion and take about a decade to refurbish all 4 units. To date, refurbishment has gone relatively smoothly and the company believes that it will adhere to the overall cost of the project with the exception of cost increases driven by Covid. The company currently expects to complete the refurbishment of Unit 3 in Q3 2023, compared to an initial completion in early 2024. Unit 1 started refurbishment in February 2022 and management expects it to return to service in the second quarter of 2025. The regulatory

framework continues to incorporate the forecasted capex to bring the units in service, so it is already reflected in both rate base and revenues without the need for OPG to file a rate case.

Exhibit 5
Darlington refurbishment timeline

Darlington	Capacity	Refurbishment start date	Refurbishment completion date
Unit 2	878	Oct-16	Jun-20
Unit 3	878	Sep-20	Q3-2023
Unit 1	878	Feb-22	Q2-2025
Unit 4	878	Q3-2023	Q3-2026

Source: Company filings

The company is moving forward with its plan to complete construction of a 300 MW SMR in 2028. We believe that new nuclear construction has very high execution risk. The OEB has determined that SMR related costs may be recorded in a nuclear development variance account (NDVA). The NDVA, which does not have a limit but is subject to prudence review, had a balance of CAD111 million at FYE 2022. The company did not incorporate any spending into its 2022-2026 rate case application. With significant spending likely and no timelines for recovery of the balance or cash recovery of carrying costs, the burden on the company's balance sheet is likely to grow over time. The company has not yet provided an SMR cost forecast.

Financial metrics to remain reasonably predictable

We expect CFO pre-WC/debt to be in the range of 20-25% over the next few years with cash flow to remain reasonably predictable, with generation levels driving some variability. The variability in generation leads to a wider range in forecast financial metrics compared to transmission and distribution companies. The primary driver of improving financial metrics over the past few years has been the significant change in the company's pension plan, which had led to a decline in our pension driven debt adjustment to CAD311 million at FYE2022 from a high of CAD5 billion at FYE2020.

We expect internally generated cash flow and debt issuances to fund the capital program, which is focused on sustaining existing assets and Darlington refurbishment. The company has credit friendly financial policies and OPG seldom pays dividends with the only dividends in recent years paid connected to asset sales (property sales, not generation facilities) that it was directed to make by the Ontario government. However, unlike public companies, we think it could be challenging to raise additional equity if required, limiting OPG's financial flexibility.

Further debt financed M&A remains a risk, although management has indicated that they plan to focus on their existing assets. We believe that any further acquisitions or investments will likely be small and similar to the 48MW Racine Hydroelectric generation facility that OPG acquired for CAD112 million on 30 December 2021.

There is some structural subordination stemming from project finance debt at Canadian contracted assets totaling about CAD2.4 billion at FYE 2022 and about CAD486 million of debt on US assets. However, unlike the vast majority of regulated utilities, there is no debt outstanding at the regulated businesses that generated about 73% of EBITDA in 2022. That, in conjunction with primarily centralized funding for OPG, results in no notching for structural subordination.

High probability of support from the Province provides an uplift to OPG's credit profile

Given the 100% ownership interest held by the Province, OPG is considered a government related issuer (GRI) under our GRI methodology. Based on our estimate of a high probability of extraordinary support in case of financial distress, the A3 credit profile incorporates 3 notches of uplift from OPG's BCA of baa3.

The company's ratings incorporate our expectation that extraordinary financial support to OPG would be forthcoming from the Province if needed. Our high support assumption considers that OPG produces more than half of the power in the Province at a comparatively low cost, making its infrastructure essential to the Ontario economy. OPG also implements government policy which can have negative credit implications. For example, in an effort to reduce and smooth rate increases for customers, Ontario Regulation 53/05 mandated the creation of the rate smoothing and deferral account (RSDA), including the financing of the RSDA at the long term

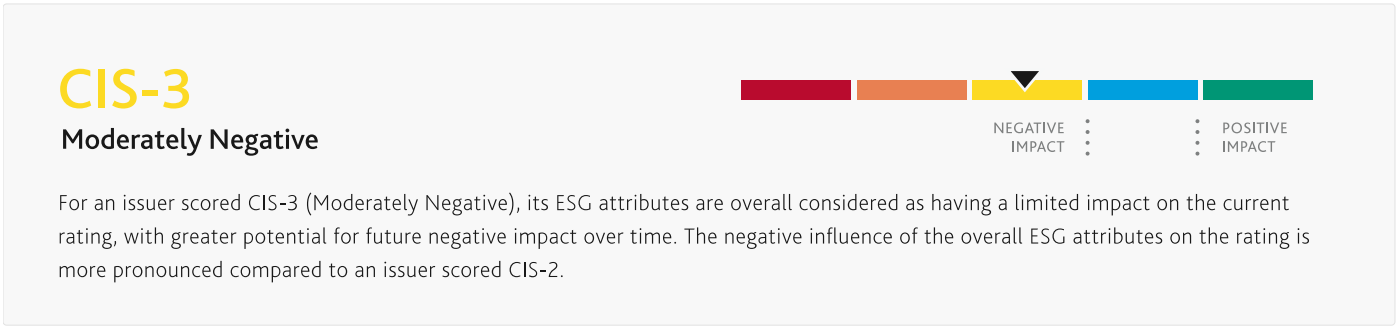
debt rate and recovery over a 10 year period after the Darlington refurbishment is complete. The Province also appoints OPG's board, reviews its business plans and is a source of debt financing through the OEFC. We do not believe there are any barriers that would prevent the Province from providing timely support.

Our assessment of high dependence reflects that both OPG and the Province largely rely on the same revenue base and share some political risks. While the OEFC is a source of financing, OPG has been increasing the level of its borrowing from public debt capital markets.

ESG considerations

OPG's ESG Credit Impact Score is CIS-3 (Moderately Negative)

Exhibit 6
ESG Credit Impact Score



Source: Moody's Investors Service

OPG's **CIS-3** indicates that ESG considerations have a limited impact on the current credit rating with potential for greater negative impact over time as a result of physical climate risks and demographic and social trends related primarily to affordability.

Exhibit 7
ESG Issuer Profile Scores



Source: Moody's Investors Service

Environmental

OPG's **E-3** score reflects exposure to physical climate risks mostly due to extreme weather patterns which is a challenge for the sector. OPG's nuclear generation assets also have exposure to waste management and pollution risks. While the company has not had any issues with its nuclear fleet or nuclear waste, it remains an inherent risk for nuclear operators. The company has limited exposure to carbon transition risks owing to its portfolio of primarily nuclear and renewable assets.

Social

OPG's **S-4** score reflects the high risk related to demographic and societal trends associated with rate pressures as evidenced by some lengthy delays associated with recovering some costs. Factors contributing to rate pressures include more expensive sources of energy in the Province, particularly some high priced legacy renewable contracts.

Governance

OPG's **G-2** score is a function of its governance that is established by its sole owner. The company has some exposure to board structure, policies, & procedure risks resulting from its sole ownership by the Province of Ontario.

ESG Issuer Profile Scores and Credit Impact Scores for OPG are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for OPG on MDC and view the ESG Scores section.

Liquidity analysis

OPG has an adequate liquidity profile driven by about CAD3.6 billion of available credit facilities, unrestricted cash and expected cash flow that together are sufficient to cover its uses for the next 12 months.

As of March 2023, OPG has a CAD1 billion committed credit facility that expires in May 2027 and a USD750 million 364 day revolving committed facility that expires in November 2023 with a one year term out provision at the company's option. Both of these facilities backstop CAD1 billion and USD750 million commercial paper programs that had no commercial paper outstanding at March 2023. In addition the company has a drawings available of CAD892 million in a facility to support SMR investments that expires in Sept 2027 and CAD750 million undrawn with the OEFC that expires in December 2026. The company has asset level facilities of CAD400 million committed facility at Lower Mattagami Energy Limited Partnership that expires in August 2027 and a USD25 million committed facility at OPG Eagle Creek Holdings LLC and subsidiaries that combined supported letters of credit of about CAD80 million. We have conservatively assumed that letters of credit of CAD379 million that are not allocated to above listed credit facilities are supported by corporate facilities in our calculations of available credit facilities.

Moody's forecasts cash flow from operations of around CAD2.4 billion in the next twelve months, in addition to the available credit facilities of CAD3.6 billion and cash and cash equivalents of CAD1.4 billion as of 31 March 2023, to be sufficient to cover the uses comprising around CAD3.5 billion of expected capital expenditures and around CAD533 million of debt maturities in the next 12 months. We expect OPG will rely in part on debt to finance its ongoing capex and refinance its upcoming debt maturities. The company's liquidity position benefits from the lack of regular dividends payable to the Province.

There are material adverse change clauses in its credit facilities that could prevent borrowings under certain circumstances, a credit and liquidity negative. Moody's expects the company to manage its program maturities, cash on hand and its swing lines in a prudent fashion.

Rating methodology and scorecard factors

Exhibit 8

Methodology Scorecard Factors

Ontario Power Generation Inc.

Regulated Electric and Gas Utilities Industry Scorecard [1][2]	Current LTM 3/31/2023		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	Baa	Baa	Baa	Baa
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Baa	Baa	Baa	Baa
b) Sufficiency of Rates and Returns	Ba	Ba	Ba	Ba
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	A	A	A	A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.1x	Aa	6x - 7x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	19.6%	Baa	20% - 25%	A
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	19.5%	A	20% - 25%	A
d) Debt / Capitalization (3 Year Avg)	40.1%	A	30% - 35%	Aa
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		Baa1		A3
HoldCo Structural Subordination Notching		0		0
a) Scorecard-Indicated Outcome		Baa1		A3
b) Actual Rating Assigned		A3		A3

Government-Related Issuer	**Factor**
a) Baseline Credit Assessment	baa3
b) Government Local Currency Rating	Aa3
c) Default Dependence	High
d) Support	High
e) Actual Rating Assigned	A3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 03/31/2023(L)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics™

Appendix

Exhibit 9

Cash Flow and Credit Metrics (CAD MM) [1]

CF Metrics	Dec-19	Dec-20	Dec-21	Dec-22	LTM Mar-23
As Adjusted					
FFO	**1,828**	**2,538**	**2,231**	**2,471**	**2,363**
+/- Other	472	81	68	178	173
CFO Pre-WC	**2,300**	**2,619**	**2,299**	**2,649**	**2,536**
+/- ΔWC	99	103	59	223	-22
CFO	**2,399**	**2,722**	**2,358**	**2,872**	**2,514**
- Div	17	19	19	17	18
- Capex	1,851	1,663	1,943	2,432	2,432
FCF	**531**	**1,040**	**396**	**423**	**64**
(CFO Pre-W/C) / Debt	19.1%	17.0%	18.1%	25.2%	24.0%
(CFO Pre-W/C - Dividends) / Debt	19.0%	16.8%	17.9%	25.0%	23.9%
FFO / Debt	15.2%	16.4%	17.6%	23.5%	22.4%
RCF / Debt	15.0%	16.3%	17.4%	23.3%	22.2%
Revenue	6,022	7,240	6,877	7,349	7,221
Interest Expense	462	514	479	482	455
Net Income	758	1,074	982	1,133	1,085
Total Assets	55,183	61,961	61,071	62,218	62,835
Total Liabilities	41,286	46,694	44,352	43,509	43,693
Total Equity	13,897	15,267	16,719	18,710	19,143

[1] All figures and ratios are calculated using Moody's estimates and standard adjustments. Periods are Financial Year-End unless indicated. LTM = Last Twelve Months
Source: Moody's Financial Metrics™

Exhibit 10

Peer Comparison Table (USD MM) [1]

	Ontario Power Generation Inc. A3 (Stable)			Public Service Enterprise Group Incorporated Baa2 (Stable)			NextEra Energy, Inc. (P)Baa1 (Stable)			Constellation Energy Generation, LLC Baa2 (Positive)		
(In US millions)	FYE Dec-20	FYE Dec-21	FYE Dec-22	FYE Dec-20	FYE Dec-21	FYE Dec-22	FYE Dec-21	FYE Dec-22	LTM Mar-23	FYE Dec-20	FYE Dec-21	LTM Mar-23
Revenue	5,403	5,486	5,651	9,603	9,722	9,800	17,997	17,069	24,782	17,603	19,649	26,414
CFO Pre-W/C	1,955	1,834	2,037	2,951	2,845	2,398	8,494	8,479	9,824	3,147	2,884	2,902
Total Debt	12,129	10,064	7,770	18,486	19,822	21,047	47,833	54,651	70,485	9,826	10,947	9,054
CFO Pre-W/C + Interest / Interest	6.1x	5.8x	6.5x	5.4x	5.5x	4.7x	5.1x	7.1x	6.2x	7.7x	8.7x	8.1x
CFO Pre-W/C / Debt	17.0%	18.1%	25.2%	16.0%	14.4%	11.4%	17.8%	15.5%	13.9%	32.0%	26.3%	32.0%
CFO Pre-W/C – Dividends / Debt	16.8%	17.9%	25.0%	10.6%	9.2%	6.3%	11.9%	9.9%	9.0%	14.4%	9.6%	27.8%
Debt / Capitalization	47.9%	40.7%	33.6%	45.2%	49.6%	52.0%	47.1%	49.9%	52.7%	34.9%	41.7%	39.0%

[1] All figures & ratios calculated using Moody's estimates & standard adjustments. FYE = Financial Year-End. LTM = Last Twelve Months. RUR* = Ratings under Review, where UPG = for upgrade and DNG = for downgrade
Source: Moody's Financial Metrics™

Exhibit 11

Ontario Power Generation Inc. Moody's - Adjusted Debt Breakdown (CAD MM)

(CAD Millions)	FYE Dec-18	FYE Dec-19	FYE Dec-20	FYE Dec-21	FYE Dec-22	LTM Mar-23
As Reported Debt	**7,878.0**	**8,390.0**	**10,382.0**	**9,848.0**	**10,217.0**	**10,241.0**
Pensions	3,656.0	3,585.0	5,023.0	2,864.0	311.0	311.0
Operating Leases	72.5	55.0	47.0	0.0	0.0	0.0
Non-Standard Adjustments	56.0	7.0	0.0	0.0	0.0	0.0
Moody's Adjusted Debt	**11,662.5**	**12,037.0**	**15,452.0**	**12,712.0**	**10,528.0**	**10,552.0**

Based on consolidated financial data of Ontario Power Generation Inc. All figures are calculated using Moody's estimates and standard adjustments
Source: Moody's Financial Metrics™

Exhibit 12

Ontario Power Generation Inc. Moody's - Adjusted EBITDA Breakdown (CAD MM)

(CAD Millions)	FYE Dec-18	FYE Dec-19	FYE Dec-20	FYE Dec-21	FYE Dec-22	LTM Mar-23
As Reported EBITDA	**2,116.0**	**2,179.0**	**3,021.0**	**2,929.0**	**3,418.0**	**3,292.0**
Pensions	-37.0	-41.0	-160.0	-146.0	-239.0	-229.0
Operating Leases	16.0	16.0	12.0	0.0	0.0	0.0
Unusual	-205.0	-52.0	0.0	-81.0	-143.0	-143.0
Moody's Adjusted EBITDA	**1,890.0**	**2,102.0**	**2,873.0**	**2,702.0**	**3,036.0**	**2,920.0**

Based on consolidated financial data of Ontario Power Generation Inc. All figures are calculated using Moody's estimates and standard adjustments
Source: Moody's Financial Metrics™

Ratings

Exhibit 13

Category	Moody's Rating
ONTARIO POWER GENERATION INC.	
Outlook	Stable
Senior Unsecured -Dom Curr	A3
Commercial Paper	P-2

Source: Moody's Investors Service

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MOODY'S RATINGS

CREDIT OPINION
24 June 2024

Update

Send Your Feedback

RATINGS

Ontario Power Generation Inc.

Domicile	Ontario, Canada
Long Term Rating	A3
Type	Senior Unsecured - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Ontario Power Generation Inc.

Update to credit analysis

Summary

Ontario Power Generation's (OPG) credit profile reflects a Baseline Credit Assessment (BCA) of baa3 with a 3 notch uplift based on its high dependence on and a high probability of extraordinary support from the Province of Ontario (Aa3 positive).

OPG's credit profile benefits from its substantial regulated nuclear and hydroelectric operations that are expected to generate the vast majority of its relatively stable cash flow. OPG's contracted assets generally exhibit long contract tenors and have a strong counterparty in the Ontario Independent Electricity System Operator (IESO, Aa3 positive) to which most assets are contracted and to which they pass through most of their costs. The company also has diversification benefits across its extensive fleet.

Offsetting these credit strengths, OPG has a large capital program that has very high levels of execution risk associated with some nuclear capital expenditures. OPG has exceeded our expectations on its Darlington nuclear refurbishment by completing its most recent unit 169 days ahead of schedule. The company's success at Darlington may carry over as it embarks on the refurbishment of units 5-8 of the Pickering nuclear generating station as well.

The company is also moving forward with a small modular reactor (SMR) program at Darlington which carries very high levels of execution risk. OPG expects the first of four potential units to be in commercial operation in 2029. While we expect these units to form part of its regulated fleet, at this time it is unclear what the extent of the regulatory support, if any, the company will have for the Pickering refurbishment and the SMR program during construction.

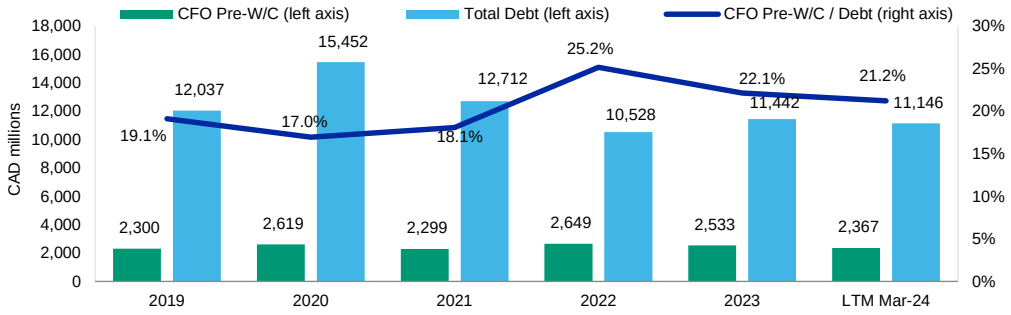
We expect the company's CFO pre-W/C to debt ratio to be sustained in the 17%-22% range over the next few years. OPG does not pay a dividend and reinvests all of its cash flow into maintaining and growing its asset base, although we expect debt to grow to fund its capital program. The company is exposed to availability risk across its fleet of generation assets and some hydrology risk. While small, its merchant generation segment has grown as a result of several 100% debt financed acquisitions and we think OPG's large capital program lessens the probability of additional, material debt financed M&A transactions.

OPG is 100% owned by the Province of Ontario and is considered a government related issuer (GRI) under our GRI methodology. The three notch uplift attributed to OPG as a GRI incorporates our expectation of an enduring link between OPG and the Province. Our high support assumption considers that OPG produces more than half of the power generated in the Province at a comparatively low cost, making its infrastructure essential to the Ontario economy. OPG also implements government policy, its board is appointed by the Province

and the Ontario Electricity Financial Corporation (OEFC, Aa3 positive), a crown corporation, is a source of debt capital for OPG. Our assessment of high dependence reflects that both OPG and the Province largely rely on the same revenue base and share some political risks.

Exhibit 1

Historical CFO Pre-W/C, Total Debt and CFO Pre-W/C to Debt



All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Periods are fiscal year-end unless indicated.
Source: Moody's Financial Metrics™

Credit strengths

» Primarily regulated generation facilities support stable cash flow generation

» Non-regulated generation segment dominated by long term contracts

» Our expectation of support from the Province of Ontario given its 100% ownership

» Diversification benefits by power generation site and units, as well as fuel source

Credit challenges

» Large capital program, which has very high levels of execution risk associated with some nuclear capital expenditures

» Uncertain regulatory support for large capital projects during construction

» Merchant cash flow entails more risk

» Availability risk across the fleet, including potential weak hydro conditions

Rating outlook

The stable outlook incorporates the following expectations:

» The company will continue to execute the Darlington nuclear refurbishment on time and budget

» It will maintain a CFO pre-WC/debt ratio in the 17-22% range over the next few years

» The relationship with the Province will remain stable and supportive

Factors that could lead to upgrade

» An upgrade is unlikely given the very high levels of execution risk associated with some of its upcoming nuclear capital expenditures

» CFO pre-WC/debt sustained above 20%

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the issuer/deal page on https://ratings.moodys.com for the most updated credit rating action information and rating history.

» An improvement in regulatory outcomes

» An upgrade of the Province to Aa1

Factors that could lead to downgrade

» Challenges, delays or cost overruns related to its capital program

» A reduction in the probability of support from the Province

» A deterioration in financial metrics such that CFO pre-WC/debt is forecast to fall below 15% on a sustained basis

» A weakening of the business risk profile by, for example, by further growing the merchant segment

Key indicators

Exhibit 2

Ontario Power Generation Inc.

	2019	2020	2021	2022	2023	LTM Mar-24
CFO Pre-W/C + Interest / Interest	7.1x	6.1x	5.8x	6.5x	7.2x	6.5x
CFO Pre-W/C / Debt	19.1%	17.0%	18.1%	25.2%	22.1%	21.2%
CFO Pre-W/C – Dividends / Debt	19.0%	16.8%	17.9%	25.0%	22.0%	21.1%
Debt / Capitalization	44.2%	47.9%	40.7%	33.6%	33.6%	32.7%

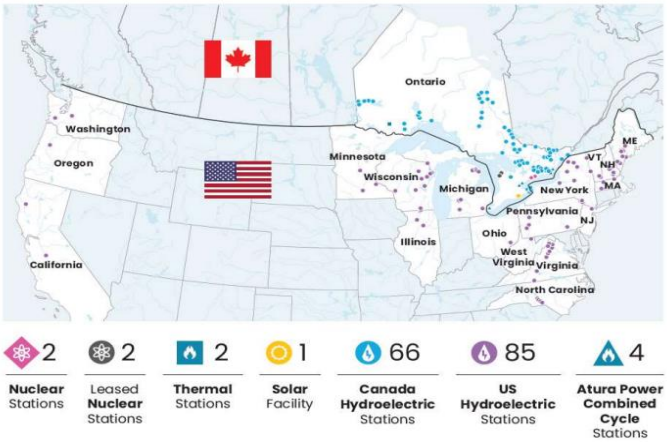
All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Periods are fiscal year-end unless indicated.
Source: Moody's Financial Metrics™

Profile

Headquartered in Toronto, Ontario, OPG is an electricity generation company wholly owned by the Province with an in-service generating capacity of 18,236 MW at March 31, 2024. OPG owns and operates 75 generating stations, 2 of which are nuclear, 66 hydroelectric, 2 thermal, 1 solar and 4 combined-cycle natural gas-fired plants in Ontario, Canada. In the US, OPG also wholly or jointly owns and operates 85 hydroelectric stations and has interests in 14 other hydroelectric and 2 solar facilities. OPG's nuclear and most of its hydroelectric facilities are regulated by the Ontario Energy Board (OEB).

Exhibit 3

OPG's service territory



Source: Company filings

Detailed credit considerations

Primarily regulated and contracted assets generate predictable cash flow

OPG's strong business risk profile is driven by its high proportion of regulated and contracted cash flow. Regulated earnings from OEB's rate regulated assets accounted for 75% of the EBITDA (all figures rounded) from its generating business segments during last twelve months end 31 March 2024, including 48% from the regulated nuclear generation segment and 27% from the regulated hydroelectric generation segment. The Atura Power combined cycle plants generated 18% of EBITDA and contracted hydroelectric and other, which has more contracted cash flow than merchant, generated 7% of EBITDA.

The company has extensive diversity by generation station and unit within each segment, reducing volatility. It also has some hydro risk, albeit low, and negligible levels of commodity price risk, a key credit positive. Unlike most other regulated utilities, OPG owns generating assets only and does not have any lower risk transmission and distribution assets. As a result, as a higher risk generation company, OPG is exposed to availability risks on all of its assets which drives more variability in its financial results compared to most T&D companies.

The company's regulated assets should provide predictable cash flow going forward. A multiyear rate plan in place from 2022-2026 establishes volumetric prices for the regulated nuclear segment and a change in Ontario Regulation 53/05 undertaken by the Province provides pricing for regulated hydroelectric assets over this period.

The nuclear generation segment benefits from diversification across 2 nuclear generating stations, with 6 (Pickering) and 4 (Darlington) operating reactors respectively, that enable the company to maintain high levels of generation and cash flow while undertaking nuclear refurbishment. Pickering Units 1 and 4 are set to be shut down in the second half of 2024.

In the second half of 2021, OPG reached a settlement with its intervenors that was subsequently approved by the OEB. The settlement led to a 2022-2026 nuclear generation revenue requirement of CAD16 billion, compared to CAD16.7 billion in the company's rate case application. Regulated prices are designed to support an allowed level of operating costs and earn a return on its capital costs for a forecast amount of generation. Significantly, the settlement supports growth in rate base over the period as the company continues to make progress on the Darlington refurbishment.

Nuclear rate base for the period 2022-2026 is allowed an ROE of 8.66% and hydroelectric 9.33% and both have equity capital of 45%. Performance that deviates by more than 300 bps in any given year may lead to a regulatory review. Regulatory lag has improved considerably with the most recent rate case, where a payments order was issued in January 2022 with new rates effective that month, although the extensive use of deferral accounts that reduce cash flow is a credit negative. Nuclear rates have significantly increased over the past several years. As recently as the first half of 2017, nuclear rates were CAD 59.29 MWh, a price that, like the table below, incorporates rates riders for variance and deferral accounts. The table below includes rates increases to both nuclear and hydroelectric rates following a 13 June 2024 OEB decision that addressed several issues, including multiple variance accounts.

Exhibit 4

	2023	2024	2025	2026
Regulated Nuclear Generation Total price ($/MWh)	109.0	107.8	111.6	123.8
Approved Nuclear Rate Base (CAD million)	8,615.0	11,033.0	12,189.0	12,992.0
Forecast Nuclear Production (TWh)	31.2	34.0	31.1	21.9
Regulated Hydroelectric Generation price ($/MWh)	44.9	47.5	47.2	47.2

Rates for 2024-2026 effective 1 July 2024
Source: Ontario Energy Board

The regulated hydroelectric facilities include 54 generating stations in Ontario across a number of river systems with prices established by an incentive rate mechanism. On 10 November 2020, the Province took steps to establish the hydroelectric base regulated price for the period 2022-2026 at the 2021 regulated price. While this provides price certainty for the period, it may be challenging at times for OPG to earn its allowed returns over the period given ongoing investments in rate base assets that exceed depreciation. Mitigating this challenge is the increase in production that will directly result from some of these investments.

The contracted hydroelectric and other generation segment consists of lower risk contracted assets in Ontario and higher risk, primarily merchant US based assets. Ontario based assets are all under contract on generally favorable terms and almost all of the contracts are with the IESO. The largest of these is the project financed Lower Mattagami Energy Limited Partnership (A1 stable). It, and other contracted hydro facilities like it, including UMH Energy Partnership (A2 stable), have strong contract terms which include limited hydro risk and contract expiries over the 2059-2067 period. The two Ontario thermal plants in this segment have substantial capacity, but are largely peaking facilities and typically have low levels of generation. They are primarily compensated based on their availability and have cost pass through provisions, however they have shorter contract tenors compared to the contracted hydro facilities.

OPG has grown its US presence and its Atura business segment through acquisitions in the past few years. The Atura Power business consists of 4 combined cycle gas plants that operate under contract with the IESO or other long term contracts on similar terms to the above mentioned thermal plants. The latest contract expiry is the 900 MW Napanee plant that operates under a 20 year contract that expires in 2040. This segment is also pursuing opportunities in battery storage and hydrogen production, including the construction of a 250MW four hour battery storage system at the site of one of its gas plants. It expects to complete construction in 2026 and the investment is supported by a 21 year capacity agreement with the IESO. The US assets have some contracts, but are primarily merchant assets with substantially more risk than the rest of the portfolio.

Large, nuclear focused capital program with varying degrees of execution risk

We expect OPG's large capital program to grow rapidly to about CAD5-6 billion a year with varying degrees of execution risk. Weighing on the company's business risk profile in particular is the risk associated with nuclear capex with the company's small modular reactor program at the very high end of the risk spectrum, with less risk associated with Pickering refurbishment and lower risk associated with Darlington refurbishment. At this time, it is unclear what regulatory support, if any, the company will have for Pickering refurbishment and the SMR program during construction. For example the company may capitalize an allowance for funds used during construction which would provide no cash flow support or it may receive cash construction work in progress which would provide comparably more support. We expect the company will publish a cost estimate associated with the SMR program within the next year. Moving forward with large projects without a public cost estimate and certainty on the degree of regulatory support during construction differentiates OPG from investor owned utilities.

Darlington refurbishment execution risk is diminishing

Execution risk associated with nuclear refurbishment at the Darlington Generation Station is diminishing given the company's strong track record of execution on the first 2 units. Unit 3 connected to the grid 169 days ahead of schedule, resulting in the production of an incremental 3TWh of electricity. The company applied more than 1000 lessons learned from Unit 2's refurbishment and applied that to Unit 3 and management continues to incorporate learnings into subsequent units. The refurbishment is tracking to its forecast cost of CAD12.8 billion with the exception of cost increases driven by COVID.

Given the success at Unit 3, management now expects Unit 1 to complete refurbishment and return to service in Q4 of 2024, well ahead of its prior projected in service date of Q2 2025. The time table for Unit 4 is the second half of 2026, although we think there is a high probability that this unit will also return to service well ahead of schedule. The regulatory framework continues to incorporate the forecasted capex to bring the units in service, so it is already reflected in both rate base and revenues without the need for OPG to file a rate case.

Exhibit 5

Darlington refurbishment timeline

Darlington	Capacity	Refurbishment start date	Refurbishment completion date
Unit 2	878	Oct-16	Jun-20
Unit 3	878	Sep-20	Jul-23
Unit 1	878	Feb-22	Q4-2024
Unit 4	878	Jul-23	H2-2026

Source: Company filings

Pickering refurbishment also moving forward but awaiting nuclear regulatory approval

Following a request from the Provincial government, OPG updated the feasibility assessment for the refurbishment of Pickering Units 5 to 8, which had been scheduled for shutdown in the coming years. Subsequently, the Provincial government requested that OPG proceed with the refurbishment of these units. In response, the company has sanctioned CAD2 billion in capital expenditure to advance the project. The refurbishment plan is contingent on receiving approvals from the Canadian Nuclear Safety Commission (CNSC). The company's schedule involves shutting down Units 5 to 8 in 2026, with a phased plan to return units to service by the mid 2030's. Units 1 and 4 are slated for shutdown in the latter half of 2024, while Units 2 and 3 were placed in safe storage more than a decade ago.

Small modular reactors entail high execution risk

The company is also planning to build four 300 MW SMR's adjacent to the Darlington station, that we view as new nuclear construction entailing very high execution risk. The company expects the first unit to be in commercial operation in 2029, and will start construction on subsequent units only after the first one is complete, with the remaining units in service in the mid-2030's. Each SMR will be a GE Hitachi BWRX-300 reactor and the company expects to yield benefits from a fleet approach.

The OEB has determined that SMR related costs may be recorded in a nuclear development variance account (NDVA). The NDVA does not have a limit but is subject to prudence review. A 13 June 2024 OEB decision approved the recovery of CAD108 million over the period 1 July 2024 through the end of 2026. These costs were associated with the non-capital preliminary planning and preparation costs that were incurred between 2020 and 2022. The company did not incorporate any SMR related spending into its 2022-2026 rate case application. With significant spending likely in the next few years and uncertainty around regulatory support during construction, the burden on the company's balance sheet is likely to grow over time. The company has not yet provided an SMR cost forecast, but we believe a cost estimate is likely following the receipt of a license to construct from the CNSC in early 2025. We believe execution risk will be highest with the first unit, with diminishing risk on subsequent units.

Financial metrics to remain reasonably predictable

We expect CFO pre-WC/debt to be in the range of 17-22% over the next few years with cash flow to remain reasonably predictable, although generation levels will drive some variability. These variations in generation result in a wider range in forecast financial metrics compared to transmission and distribution companies. We expect the remaining units at Darlington to be completed ahead of schedule, providing some support to financial metrics. Nonetheless, pressure on metrics may build in the latter part of the decade as the company progresses with both the Pickering refurbishment and the SMR's since they do not currently have any form of cash flow recovery during construction and will result in significant debt issuances.

We expect both internally generated cash flow and debt issuances to fund the capital program, which is focused primarily on nuclear capex, sustaining capital and other smaller projects that have relatively low levels of execution risk. The company exhibits credit supportive financial policies and OPG seldom pays a dividend. However, the offset to this is that, unlike public companies, we think it could be challenging to issue equity if required, limiting OPG's financial flexibility.

Further debt financed M&A remains a risk, although management has indicated that they plan to focus on their existing assets and, given the planned nuclear projects, the company has ample organic growth opportunities.

There is some structural subordination stemming from project finance debt at Canadian contracted assets totaling about CAD2.4 billion at 31 March 2024 and about CAD486 million of debt on US assets. However, unlike the vast majority of regulated utilities, there is no debt outstanding at the key regulated businesses that generated about 72% of EBITDA in 2023. That, in conjunction with primarily centralized funding at OPG, results in no notching for structural subordination.

A driver of improving financial metrics over the past few years has been the significant change in the company's pension plan, which had led to a decline in our pension driven debt adjustment to CAD900 million at 31 March 2024 from a high of CAD5 billion at FYE2020, supporting financial metrics. The company is also eligible for different types of investment tax credits, and these will likely provide incremental support to the company's financial profile over time.

High probability of support from the Province provides an uplift to OPG's credit profile

Given the 100% ownership interest of the Province, OPG is considered a government related issuer (GRI) under our GRI methodology. Based on our estimate of a high probability of extraordinary support in case of financial distress, the A3 credit profile incorporates 3 notches of uplift from OPG's BCA of baa3.

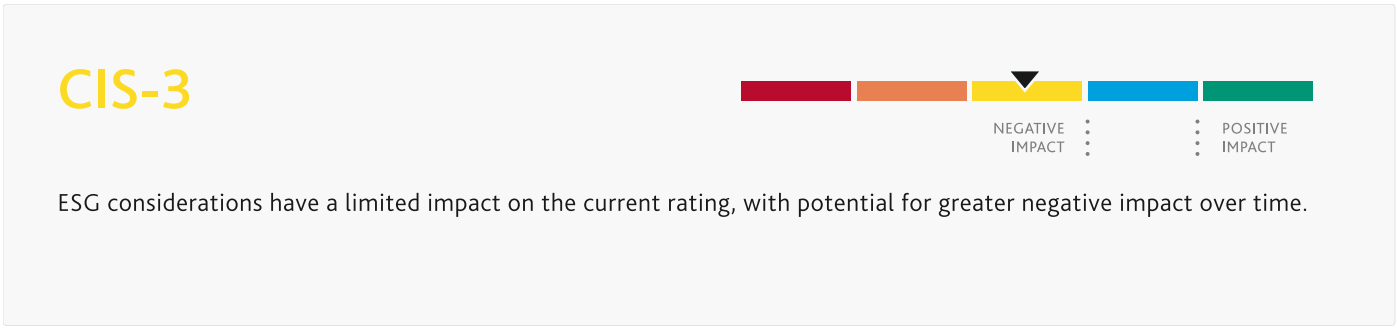
The company's ratings incorporate our expectation that extraordinary financial support to OPG would be forthcoming from the Province if needed. Our high support assumption considers that OPG produces more than half of the power in the Province at a comparatively low cost, making its infrastructure essential to the Ontario economy. OPG also implements government policy which can have negative credit implications. For example, in an effort to reduce and smooth rate increases for customers, Ontario Regulation 53/05 mandated the creation of the rate smoothing and deferral account (RSDA), including the financing of the RSDA at the long term debt rate and recovery over a 10 year period after the Darlington refurbishment is complete. The Province also appoints OPG's board, reviews its business plans and is a source of debt financing through the OEFC. We do not believe there are any barriers that would prevent the Province from providing timely support.

Our assessment of high dependence reflects that both OPG and the Province largely rely on the same revenue base and share some political risks. While the OEFC is a source of financing, OPG has been increasing the level of its borrowing from public debt capital markets.

ESG considerations

Ontario Power Generation Inc.'s ESG credit impact score is CIS-3

Exhibit 6
ESG credit impact score



Source: Moody's Ratings

OPG's **CIS-3** indicates that ESG considerations have a limited impact on the current credit rating with potential for greater negative impact over time as a result of physical climate risks and demographic and social trends related primarily to affordability.

Exhibit 7
ESG issuer profile scores



Source: Moody's Ratings

Environmental

OPG's **E-3** score reflects exposure to physical climate risks mostly due to extreme weather patterns which is a challenge for the sector. OPG's nuclear generation assets also have exposure to waste management and pollution risks. While the company has not had any issues with its nuclear fleet or nuclear waste, it remains an inherent risk for nuclear operators. The company has limited exposure to carbon transition risks owing to its portfolio of primarily nuclear and renewable assets.

Social

OPG's **S-4** score reflects the high risk related to demographic and societal trends associated with rate pressures as evidenced by some lengthy delays associated with recovering some costs. Factors contributing to rate pressures include more expensive sources of energy in the Province, particularly some high priced legacy renewable contracts.

Governance

OPG's **G-2** score is a function of its governance that is established by its sole owner. The company has some exposure to board structure, policies, & procedure risks resulting from its sole ownership by the Province of Ontario.

ESG Issuer Profile Scores and Credit Impact Scores for the rated entity/transaction are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for the entity/transaction on MDC and view the ESG Scores section.

Liquidity analysis

OPG has an adequate liquidity profile driven by about CAD3.3 billion of available credit facilities, unrestricted cash and expected cash flow that together are sufficient to cover its uses for the next 12 months.

As of March 31, 2024, OPG had a CAD1 billion committed credit facility that expires in May 2028 and a USD750 million 364 day revolving committed facility that expires in November 2024 with a one year term out provision at the company's option. Both of these facilities backstop CAD1 billion and USD750 million commercial paper programs that had no commercial paper outstanding at December 2023. In addition, the company has drawings of CAD571 million available on a facility from the Canada Infrastructure Bank to support SMR investments that expires in Sept 2027 and CAD750 million undrawn on a facility with the OEFC that expires in December 2026.

The company has asset level facilities of CAD460 million committed at Lower Mattagami Energy Limited Partnership that expires in August 2028 and a USD20 million committed facility at OPG Eagle Creek Holdings LLC and subsidiaries that combined supported letters of credit of about CAD85 million. We have conservatively assumed that letters of credit of CAD445 million that are not allocated to above listed credit facilities are supported by corporate facilities and are not reflected in our calculations of available credit facilities.

Moody's forecasts cash flow from operations over the next twelve months to be close to the CAD2.4 billion it generated over the last twelve months. In addition to the available credit facilities of CAD3.3 billion and cash and cash equivalents (including restricted cash of CAD22 million at 31 December 2023) of CAD0.9 billion as of 31 March 2024, these sources should be sufficient to cover uses comprising CAD5-6 billion of expected capital expenditures and around CAD203 million of debt maturities in the next 12 months. We expect OPG will rely in part on debt to finance its ongoing capex and refinance its upcoming debt maturities. The company's liquidity position benefits from the lack of regular dividends payable to the Province.

There are material adverse change clauses in its credit facilities that could prevent borrowings under certain circumstances, a credit and liquidity negative. Moody's expects the company to manage its program maturities, cash on hand and its swing lines in a prudent fashion.

Rating methodology and scorecard factors

The principal methodology used for this rating is the Regulated Electric and Gas Utilities rating methodology. The scorecard- indicated outcome for our 12-18 months forward view is Baa1, two notches above the BCA of baa3 with the difference attributable to elevated capex risk and OPG's generation asset base compared to all peers having at least some lower risk transmission and distribution assets.

Exhibit 8

Methodology scorecard factors

Ontario Power Generation Inc.

Regulated Electric and Gas Utilities Industry Scorecard	Current LTM 3/31/2024		Moody's 12-18 Month Forward View	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	Baa	Baa	Baa	Baa
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Baa	Baa	Baa	Baa
b) Sufficiency of Rates and Returns	Ba	Ba	Ba	Ba
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	A	A	A	A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.5x	Aa	6x - 8x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	21.7%	Baa	17% - 22%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	21.6%	A	17% - 22%	A
d) Debt / Capitalization (3 Year Avg)	35.2%	A	35% - 40%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		Baa1		Baa1
HoldCo Structural Subordination Notching		0		0
a) Scorecard-Indicated Outcome		Baa1		Baa1
b) Actual Rating Assigned		A3		A3

Government-Related Issuer	**Factor**
a) Baseline Credit Assessment	baa3
b) Government Local Currency Rating	Aa3
c) Default Dependence	High
d) Support	High
e) Actual Rating Assigned	A3

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. Moody's forecasts are Moody's opinion and do not represent the views of the issuer.
Sources: Moody's Financial Metrics™ and Moody's Ratings forecasts

Appendix

Exhibit 9

Peer comparison

Ontario Power Generation Inc.

	Ontario Power Generation Inc. A3 Stable			Constellation Energy Generation, LLC Baa1 Stable			NextEra Energy, Inc. Baa1 Stable		
(in $ millions)	FY Dec-22	FY Dec-23	LTM Mar-24	FY Dec-21	FY Dec-22	FY Dec-23	FY Dec-22	FY Dec-23	LTM Mar-24
Revenue	5,651	5,510	5,468	19,649	24,440	24,918	20,956	28,114	27,129
CFO Pre-W/C	2,037	1,877	1,756	2,884	2,753	3,990	10,108	11,439	12,110
Total Debt	7,770	8,677	8,236	10,947	8,193	11,294	64,810	72,206	78,432
CFO Pre-W/C + Interest / Interest	6.5x	7.2x	6.5x	8.7x	8.7x	8.9x	15.0x	4.2x	5.6x
CFO Pre-W/C / Debt	25.2%	22.1%	21.2%	26.3%	33.6%	35.3%	15.6%	15.8%	15.4%
CFO Pre-W/C – Dividends / Debt	25.0%	22.0%	21.1%	9.6%	31.3%	24.4%	10.3%	10.5%	10.3%
Debt / Capitalization	33.6%	33.6%	32.7%	41.7%	36.2%	43.6%	52.2%	50.5%	52.1%

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics™

Exhibit 10

Moody's – adjusted cash flow metrics

Ontario Power Generation Inc.

(in CAD millions)	2019	2020	2021	2022	2023	LTM Mar-24
FFO	**1,828.2**	**2,538.3**	**2,231.0**	**2,471.0**	**2,590.0**	**2,409.0**
+/- Other	472.0	81.0	68.0	178.0	(57.0)	(42.0)
CFO Pre-WC	**2,300.2**	**2,619.3**	**2,299.0**	**2,649.0**	**2,533.0**	**2,367.0**
+/- ΔWC	99.0	103.0	59.0	223.0	(114.0)	114.0
CFO	**2,399.2**	**2,722.3**	**2,358.0**	**2,872.0**	**2,419.0**	**2,481.0**
- Div	17.0	19.0	19.0	17.0	19.0	19.0
- Capex	1,851.2	1,663.3	1,943.0	2,432.0	2,782.0	2,864.0
FCF	**531.0**	**1,040.0**	**396.0**	**423.0**	**(382.0)**	**(402.0)**
(CFO Pre-W/C) / Debt	19.1%	17.0%	18.1%	25.2%	22.1%	21.2%
(CFO Pre-W/C - Dividends) / Debt	19.0%	16.8%	17.9%	25.0%	22.0%	21.1%
FFO / Debt	15.2%	16.4%	17.6%	23.5%	22.6%	21.6%
RCF / Debt	15.0%	16.3%	17.4%	23.3%	22.5%	21.4%
Revenue	6,022.0	7,240.0	6,877.0	7,349.0	7,434.0	7,371.0
Interest Expense	374.9	514.0	478.6	482.0	411.6	428.2
Net Income	832.8	1,073.8	981.5	1,132.6	1,448.9	1,230.2
Total Assets	55,183.0	61,961.0	61,071.0	62,218.0	65,569.0	65,899.0
Total Liabilities	41,286.4	46,694.4	44,351.6	43,508.5	45,261.2	45,331.2
Total Equity	13,896.6	15,266.6	16,719.4	18,709.5	20,307.9	20,567.9

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Periods are fiscal year-end unless indicated.
Source: Moody's Financial Metrics™

Exhibit 11

Moody's – adjusted Debt reconciliation

Ontario Power Generation Inc.

(in CAD millions)	2019	2020	2021	2022	2023	LTM Mar-24
As reported debt	**8.4**	**10.4**	**9.8**	**10.2**	**10.5**	**10.2**
Pensions	3.6	5.0	2.9	0.3	0.9	0.9
Operating Leases	0.1	0.0	-	-	-	-
Non-Standard Adjustments	0.0	-	-	-	-	-
Moody's – adjusted debt	**12.0**	**15.5**	**12.7**	**10.5**	**11.4**	**11.1**

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Periods are fiscal year-end unless indicated.
Source: Moody's Financial Metrics™

Exhibit 12

Moody's – adjusted EBITDA reconciliation

Ontario Power Generation Inc.

(in CAD millions)	2019	2020	2021	2022	2023	LTM Mar-24
As reported EBITDA	**2.2**	**3.0**	**2.9**	**3.4**	**3.6**	**3.4**
Pensions	(0.0)	(0.2)	(0.1)	(0.2)	(0.2)	(0.2)
Operating Leases	0.0	0.0	-	-	-	-
Unusual	(0.1)	-	(0.1)	(0.1)	-	-
Moody's – adjusted EBITDA	**2.1**	**2.9**	**2.7**	**3.0**	**3.4**	**3.2**

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Periods are fiscal year-end unless indicated.
Source: Moody's Financial Metrics™

Ratings

Exhibit 13

Category	Moody's Rating
ONTARIO POWER GENERATION INC.	
Outlook	Stable
Senior Unsecured -Dom Curr	A3
Commercial Paper	P-2

Source: Moody's Ratings

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MOODY'S RATINGS

CREDIT OPINION
30 June 2025

Update

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RATINGS

Ontario Power Generation Inc.

Domicile	Ontario, Canada
Long Term Rating	A3
Type	Senior Unsecured - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Ontario Power Generation Inc.

Update to credit analysis

Summary

Ontario Power Generation's (OPG) credit profile reflects a Baseline Credit Assessment (BCA) of baa3 with a 3 notch uplift based on its high dependence on and a high probability of extraordinary support from the Province of Ontario (Aa3 stable).

OPG's credit profile benefits from its substantial regulated nuclear and hydroelectric operations that are expected to generate the vast majority of its relatively stable cash flow. OPG's contracted assets generally exhibit long contract tenors and have a strong counterparty in the Ontario Independent Electricity System Operator (IESO, Aa3 stable) to which most assets are contracted and to which they pass through most of their costs. The company also has diversification benefits across its extensive fleet.

Offsetting these credit strengths, OPG has a large capital program that has very high levels of execution risk associated with some nuclear capital expenditures. OPG has exceeded our expectations on its Darlington nuclear refurbishment by completing its most recent unit about 5 months ahead of schedule. The company's success at Darlington may carry over as it moves forward with the refurbishment of units 5-8 of the Pickering nuclear generating station as well.

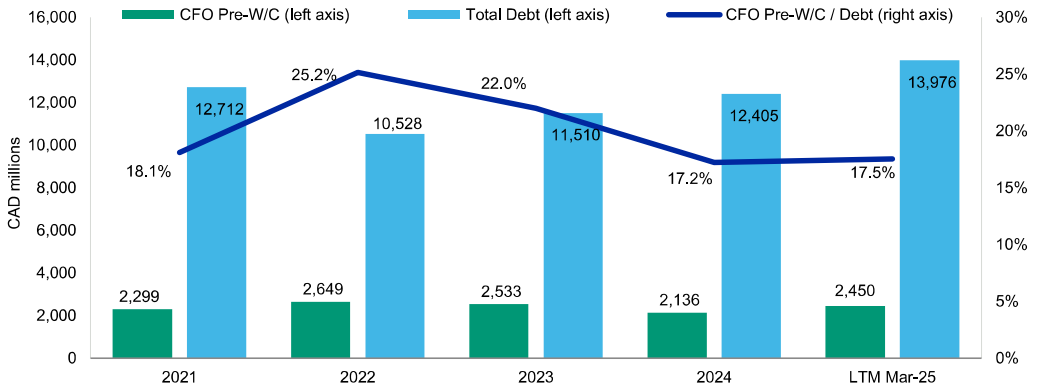
The company has also begun construction on a CAD20.9 billion small modular reactor (SMR) program at Darlington which carries very high levels of execution risk. OPG expects the first of four potential units to be in commercial operation in 2030. While we expect all of these units to form part of its regulated fleet, at this time it is unclear what the extent of the regulatory support, if any, the company will have for the Pickering refurbishment and the SMR program during construction, although the government has solicited feedback on credit friendly measures.

We expect the company's CFO pre-W/C to debt ratio to be sustained in the 15%-20% range over the next few years. OPG does not pay a dividend and reinvests all of its cash flow into maintaining and growing its asset base, although we expect debt to grow to fund its capital program. The company is exposed to availability risk across its fleet of generation assets and some hydrology risk. While small, its merchant generation segment has grown in the past as a result of several 100% debt financed acquisitions and we think OPG's large capital program diminishes the probability of additional, material debt financed M&A transactions.

OPG is 100% owned by the Province of Ontario and is considered a government related issuer (GRI) under our GRI methodology. The three notch uplift attributed to OPG as a GRI incorporates our expectation of an enduring link between OPG and the Province. Our high support assumption considers that OPG produces more than half of the power generated in the Province at a comparatively low cost, making its infrastructure essential to the Ontario economy. OPG also implements government policy, its board is appointed by the Province and the Ontario Electricity Financial Corporation (OEFC, Aa3 stable), a crown corporation, is

a source of debt capital for OPG. Our assessment of high dependence reflects that both OPG and the Province largely rely on the same revenue base and share some political risks.

Exhibit 1
Historical CFO Pre-W/C, Total Debt and CFO Pre-W/C to Debt



All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Periods are fiscal year-end unless indicated.
Source: Moody's Financial Metrics™

Credit strengths

» Primarily regulated generation facilities support stable cash flow generation

» Non-regulated generation segment dominated by long term contracts

» Our expectation of support from the Province of Ontario given its 100% ownership

» Diversification benefits by power generation site and units, as well as fuel source

Credit challenges

» Large capital program, which has very high levels of execution risk associated with some nuclear capital expenditures

» Uncertain regulatory support for large capital projects during construction

» Merchant cash flow entails more risk

» Availability risk across the fleet, including potential weak hydro conditions

Rating outlook

The stable outlook incorporates the following expectations:

» The company will continue to execute the Darlington nuclear refurbishment on time and budget

» It will maintain a CFO pre-WC/debt ratio in the 15-20% range over the next few years

» The relationship with the Province will remain stable and supportive

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the issuer/deal page on https://ratings.moodys.com for the most updated credit rating action information and rating history.

Factors that could lead to upgrade

» An upgrade is unlikely given the very high levels of execution risk associated with some of its upcoming nuclear capital expenditures

» CFO pre-WC/debt sustained above 20%

» An improvement in regulatory outcomes

» An upgrade of the Province to Aa1

Factors that could lead to downgrade

» Challenges, delays or cost overruns related to its capital program

» A reduction in the probability of support from the Province

» A deterioration in financial metrics such that CFO pre-WC/debt is forecast to fall below 15% on a sustained basis

» A weakening of the business risk profile by, for example, further growing the merchant segment

Key indicators

Exhibit 2

Ontario Power Generation Inc.

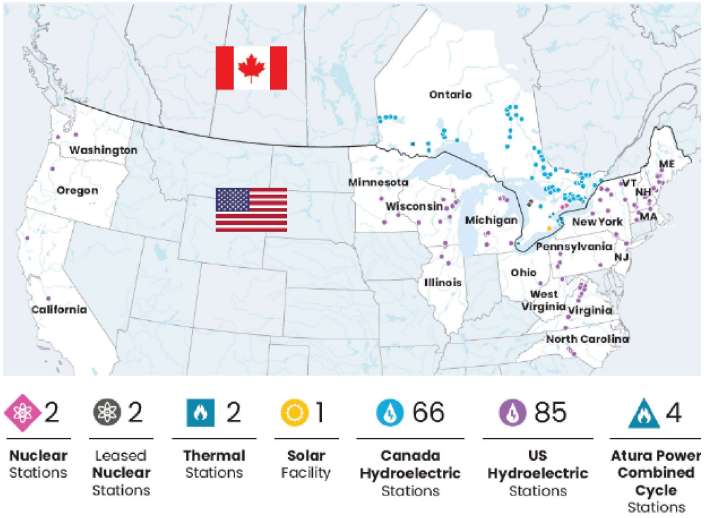
	2020	2021	2022	2023	2024	LTM Mar-25
CFO Pre-W/C + Interest / Interest	6.1x	5.8x	6.5x	7.2x	5.6x	6.2x
CFO Pre-W/C / Debt	17.0%	18.1%	25.2%	22.0%	17.2%	17.5%
CFO Pre-W/C – Dividends / Debt	16.8%	17.9%	25.0%	21.8%	17.1%	17.4%
Debt / Capitalization	47.9%	40.7%	33.6%	33.7%	34.0%	36.2%

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Periods are fiscal year-end unless indicated.
Source: Moody's Financial Metrics™

Profile

Headquartered in Toronto, Ontario, OPG is an electricity generation company wholly owned by the Province with an in-service generating capacity of 18,094 MW at 31 March 2025. OPG owns and operates 75 generating stations, 2 of which are nuclear, 66 hydroelectric, 2 thermal, 1 solar and 4 combined-cycle natural gas-fired plants in Ontario, Canada. In the US, OPG also wholly or jointly owns and operates 85 hydroelectric stations and has interests in 14 other hydroelectric and 2 solar facilities. OPG's nuclear and most of its hydroelectric facilities are regulated by the Ontario Energy Board (OEB).

Exhibit 3
OPG's service territory



Source: Company filings

Detailed credit considerations

Primarily regulated and contracted assets generate predictable cash flow

OPG's strong business risk profile is driven by its high proportion of regulated and contracted cash flow. Regulated earnings from OEB's rate regulated assets accounted for 73% of the EBITDA (all figures rounded) from its generating business segments during the LTM ending March 2025, including 45% from the regulated nuclear generation segment and 27% from the regulated hydroelectric generation segment. The Atura Power combined cycle plants generated 14% of EBITDA and contracted hydroelectric and other, which has more contracted cash flow than merchant, generated 14% of EBITDA.

The company has extensive diversity by generation station and unit within each segment, reducing volatility. It also has some hydro risk, albeit low, and negligible levels of commodity price risk, a key credit positive. Unlike most other regulated utilities, OPG owns generating assets only and does not have any lower risk transmission and distribution assets. As a result, as a higher risk generation company, OPG is exposed to availability risks on all of its assets which drives more variability in its financial results compared to most T&D companies.

The company's regulated assets should provide predictable cash flow going forward. A multiyear rate plan in place from 2022-2026 establishes volumetric prices for the regulated nuclear segment and a change in Ontario Regulation 53/05 undertaken by the Province provides pricing for regulated hydroelectric assets over this period.

The nuclear generation segment benefits from diversification across 2 nuclear generating stations, with 4 units at Pickering and 4 units at Darlington able to generate electricity absent shutdowns and refurbishments. This enables the company to maintain high levels of generation and cash flow while undertaking nuclear refurbishment. Pickering Units 1 and 4 were permanently shut down in Q4 2024.

In the second half of 2021, OPG reached a settlement with its intervenors that was subsequently approved by the OEB. The settlement led to a 2022-2026 nuclear generation revenue requirement of CAD16 billion, compared to CAD16.7 billion in the company's rate case application. Regulated prices are designed to support an allowed level of operating costs and earn a return on its capital costs for a forecast amount of generation. Significantly, the settlement supports growth in rate base over the period as the company continues to make progress on the Darlington refurbishment.

Nuclear rate base for the period 2022-2026 is allowed an ROE of 8.66% and hydroelectric 9.33% and both have equity capital of 45%. Performance that deviates by more than 300 bps in any given year may lead to a regulatory review. Regulatory lag has improved considerably with the most recent rate case, where a payments order was issued in January 2022 with new rates effective that month, although the extensive use of deferral accounts that reduce cash flow is a credit negative. Nuclear rates have significantly increased over the past several years. As recently as the first half of 2017, nuclear rates were CAD 59.29 MWh, a price that, like the table below,

incorporates rates riders for variance and deferral accounts. The table below includes rates increases to both nuclear and hydroelectric rates following a 13 June 2024 OEB decision that addressed several issues, including multiple variance accounts.

Exhibit 4

	2023	2024	2025	2026
Regulated Nuclear Generation Total price ($/MWh)	109.0	107.8	111.6	123.8
Approved Nuclear Rate Base (CAD million)	8,615.0	11,033.0	12,189.0	12,992.0
Forecast Nuclear Production (TWh)	31.2	34.0	31.1	21.9
Regulated Hydroelectric Generation price ($/MWh)	44.9	47.5	47.2	47.2

Rates for 2024-2026 effective 1 July 2024
Source: Ontario Energy Board

The regulated hydroelectric facilities include 54 generating stations in Ontario across a number of river systems with prices established by an incentive rate mechanism. On 10 November 2020, the Province took steps to establish the hydroelectric base regulated price for the period 2022-2026 at the 2021 regulated price. While this provides price certainty for the period, it challenges OPG to earn its allowed returns over the period given ongoing investments in rate base assets that exceed depreciation. Mitigating this challenge is the increase in production that will directly result from some of these investments.

The contracted hydroelectric and other generation segment consists of lower risk contracted assets in Ontario and higher risk, primarily merchant US based assets. Ontario based assets are all under contract on generally favorable terms and almost all of the contracts are with the IESO. The largest of these is the project financed Lower Mattagami Energy Limited Partnership (A1 stable). It, and other contracted hydro facilities like it, including UMH Energy Partnership (A2 stable), have strong contract terms which include limited hydro risk and contract expiries over the 2059-2067 period. The two Ontario thermal plants in this segment have substantial capacity, but are largely peaking facilities and typically have low levels of generation. They are primarily compensated based on their availability and have cost pass through provisions, however they have shorter contract tenors compared to the contracted hydro facilities.

The Atura Power business consists of 4 combined cycle gas plants that operate under contract with the IESO on similar terms to the above mentioned thermal plants. The latest contract expiry is the 900 MW Napanee plant that operates under a 20 year contract that expires in 2040. This segment includes a capacity agreement to build a 250MW four hour battery storage system at the site of one of its gas plants. It expects to complete construction in 2026 and the investment is supported by a 21 year capacity agreement with the IESO. The US assets have some contracts, but are primarily merchant assets with substantially more risk than the rest of the portfolio.

Large, nuclear focused capital program with varying degrees of execution risk

We expect OPG's large capital program to grow rapidly to about CAD5-7 billion a year with varying degrees of execution risk. Weighing on the company's business risk profile in particular is the risk associated with nuclear capex. The company's CAD20.9 billion small modular reactor program is at the very high end of the risk spectrum, with less risk associated with Pickering refurbishment and lower risk associated with the almost completed Darlington refurbishment. At this time, it is unclear what regulatory support, if any, the company will have for Pickering refurbishment and the SMR program during construction. However the government concluded a public comment period on 26 June 2025 where it was soliciting feedback on concurrent cost recovery for nuclear construction that would apply to both the SMR program and Pickering refurbishment and allow OPG to sell a portion of the SMR project to investors. Both measures would be credit positive for OPG, but the financial benefit depends on key assumptions. The company has not yet released a cost estimate for Pickering refurbishment. The ability to move forward with large projects without a public cost estimate and certainty on the degree of regulatory support during construction differentiates OPG from investor owned utilities.

Darlington refurbishment execution risk is diminishing

Execution risk associated with nuclear refurbishment at the Darlington Generation Station is diminishing given the company's strong track record of execution on the first 3 units. Unit 3 connected to the grid 169 days ahead of schedule, resulting in the production of an incremental 3TWh of electricity. Similarly the company returned Unit 1 to service 5 months ahead of schedule. The company applied more than 1000 lessons learned from Unit 2's refurbishment and applied those lessons learned to subsequent units. The company

continues to incorporate best practices and techniques into subsequent units. The refurbishment is tracking to its forecast cost of CAD12.8 billion.

The time table for Unit 4 is the second half of 2026, although we think there is a high probability that this unit will also return to service ahead of schedule based on the company's track record. The regulatory framework continues to incorporate the forecasted capex to bring the units in service, so it is already reflected in both rate base and revenues without the need for OPG to file a rate case.

Exhibit 5
Darlington refurbishment timeline

Darlington	Capacity	Refurbishment start date	Refurbishment completion date
Unit 2	878	Oct-16	Jun-20
Unit 3	878	Sep-20	Jul-23
Unit 1	878	Feb-22	Nov-24
Unit 4	878	Jul-23	H2-2026

Source: Company filings

Pickering refurbishment also moving forward but awaiting nuclear regulatory approval

Following a request from the Provincial government, OPG updated the feasibility assessment for the refurbishment of Pickering Units 5 to 8, which had been scheduled for shutdown in the coming years. Subsequently, the Provincial government requested that OPG proceed with the refurbishment of these units. In response, the company sanctioned CAD2 billion in capital expenditure to advance the project. The refurbishment plan is contingent on receiving approvals from the Canadian Nuclear Safety Commission (CNSC). The company's schedule involves shutting down Units 5 to 8 in 2026, with a phased plan to return units to service by the mid 2030's. Units 1 and 4 were shutdown in Q4 2024, while Units 2 and 3 were placed in safe storage more than a decade ago.

On 23 January 2025, the Province announced its approval of OPG's plan to proceed with the project definition phase as the next step towards the refurbishment. OPG's approved budget for this work is $4.1 billion, bringing the total Board-approved budget for the project to date to $6.2 billion.

Small modular reactors entail high execution risk

Following the receipt of a license to construct on 4 April 2025, the company has started construction on the first of four 300 MW SMR's adjacent to the Darlington station, that we view as new nuclear construction entailing very high execution risk. The company expects the first unit to be in commercial operation in 2030, and will start construction on subsequent units as the first one is complete, with the remaining units in service in the mid-2030's. The gradual capacity expansion should reduce the risk of cost overruns. Each SMR will be a GE Hitachi BWRX-300 reactor and the company expects to yield benefits from a fleet approach.

The CAD20.9 billion Darlington SMR project has very high levels of execution risk as a first of a kind nuclear project. Nuclear operators have a poor track record of completing the construction of new nuclear capacity on time and budget, with cost overruns often measured in billions, and delays measured in years. We believe execution risk will be highest with the first unit, with diminishing risk on subsequent units as the company incorporates lessons learned from the construction of each unit into subsequent units. While we expect OPG to recover prudently incurred costs, we may not know whether the company will be able to recover any potential cost overruns until the Darlington SMR project is completed. We view the prospects for some form of government and regulatory support as high given the government's public request for comment.

The OEB has determined that SMR related costs may be recorded in a nuclear development variance account (NDVA). The NDVA does not have a limit but is subject to prudence review. A 13 June 2024 OEB decision approved the recovery of CAD108 million over the period 1 July 2024 through the end of 2026. These costs were associated with the non-capital preliminary planning and preparation costs that were incurred between 2020 and 2022. The company did not incorporate any SMR related spending into its 2022-2026 rate case application.

Near term financial metrics are reasonably predictable

We expect CFO pre-WC/debt to be in the range of 15-20% over the next few years with cash flow to remain reasonably predictable, although generation levels will drive some variability. These variations in generation result in a wider range in forecast financial metrics compared to transmission and distribution companies. We expect the remaining unit at Darlington to be completed ahead of schedule, providing some support to financial metrics.

There remains uncertainty over the trajectory of financial metrics as a result of the nuclear capital program. We expect that the company will be issuing a significant amount of debt to finance the capital program for the foreseeable future, putting downward pressure on financial metrics. While we think some form of government and/or regulatory support for the Darlington SMR project and Pickering refurbishment is likely, there is no clarity yet.

We expect both internally generated cash flow and debt issuances to fund the capital program, which is focused primarily on nuclear capex, sustaining capital and other smaller projects that have relatively low levels of execution risk. The company exhibits credit supportive financial policies and OPG seldom pays a dividend. However, the offset to this is that, unlike public companies, we think it could be challenging to issue equity if required, limiting OPG's financial flexibility.

Given the size of the capital program, we think that further debt financed M&A is increasingly unlikely. Management has indicated that they plan to focus on their existing assets and, given the planned nuclear projects, the company has ample organic growth opportunities.

There is some structural subordination stemming from project finance debt at Canadian contracted assets totaling about CAD2.4 billion at 31 March 2025 and about CAD516 million of debt on US assets. However, unlike the vast majority of regulated utilities, there is no debt outstanding at the key regulated businesses that generated about 69% of EBITDA in 2024. That, in conjunction with primarily centralized funding at OPG, results in no notching for structural subordination.

High probability of support from the Province provides an uplift to OPG's credit profile

Given the 100% ownership interest of the Province, OPG is considered a government related issuer (GRI) under our GRI methodology. Based on our estimate of a high probability of extraordinary support in case of financial distress, the A3 credit profile incorporates 3 notches of uplift from OPG's BCA of baa3.

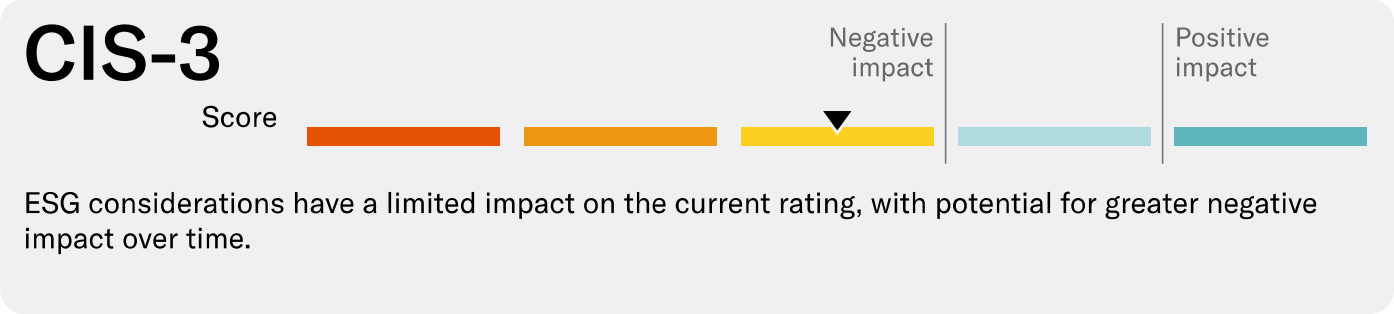
The company's ratings incorporate our expectation that extraordinary financial support to OPG would be forthcoming from the Province if needed. Our high support assumption considers that OPG produces more than half of the power in the Province at a comparatively low cost, making its infrastructure essential to the Ontario economy. OPG also implements government policy which can have negative credit implications. For example, in an effort to reduce and smooth rate increases for customers, Ontario Regulation 53/05 mandated the creation of the rate smoothing and deferral account (RSDA), including the financing of the RSDA at the long term debt rate and recovery over a 10 year period after the Darlington refurbishment is complete. The Province also appoints OPG's board, reviews and approves some aspects of its business plans and is a source of debt financing through the OEFC. We do not believe there are any barriers that would prevent the Province from providing timely support.

Our assessment of high dependence reflects that both OPG and the Province largely rely on the same revenue base and share some political risks. While the OEFC is a source of financing, OPG has been increasing the level of its borrowing from public debt capital markets.

ESG considerations

Ontario Power Generation Inc.'s ESG credit impact score is CIS-3

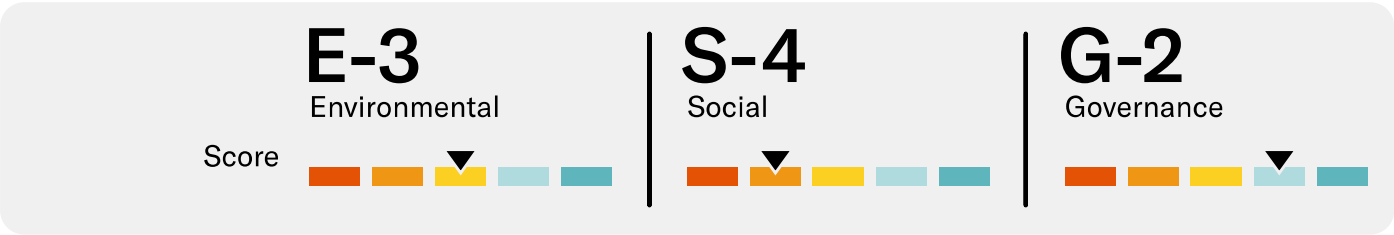
Exhibit 6
ESG credit impact score



Source: Moody's Ratings

OPG's **CIS-3** indicates that ESG considerations have a limited impact on the current credit rating with potential for greater negative impact over time as a result of physical climate risks and demographic and social trends related primarily to affordability.

Exhibit 7
ESG issuer profile scores



Source: Moody's Ratings

Environmental

OPG's **E-3** score reflects exposure to physical climate risks mostly due to extreme weather patterns which is a challenge for the sector. OPG's nuclear generation assets also have exposure to waste management and pollution risks. While the company has not had any issues with its nuclear fleet or nuclear waste, it remains an inherent risk for nuclear operators. The company has limited exposure to carbon transition risks owing to its portfolio of primarily nuclear and renewable assets.

Social

OPG's **S-4** score reflects the high risk related to demographic and societal trends associated with rate pressures as evidenced by some lengthy delays associated with recovering some costs. Factors contributing to rate pressures include more expensive sources of energy in the Province, particularly some high priced legacy renewable contracts.

Governance

OPG's **G-2** score is a function of its governance that is established by its sole owner. The company has some exposure to board structure, policies, & procedure risks resulting from its sole ownership by the Province of Ontario.

ESG Issuer Profile Scores and Credit Impact Scores for the rated entity/transaction are available on Moodys.com. In order to view the latest scores, please click here to go to the landing page for the entity/transaction on MDC and view the ESG Scores section.

Liquidity analysis

OPG has an adequate liquidity profile driven by about CAD3.6 billion of available credit facilities, unrestricted cash and expected cash flow that together are sufficient to cover its uses for the next 12 months.

As of 31 March 2025, OPG had a CAD1 billion committed credit facility that expires in May 2029 and a USD750 million 364 day revolving committed facility that expires in November 2025 with a one year term out provision at the company's option. Both of these facilities backstop CAD1 billion and USD750 million commercial paper programs that had CAD591 million commercial paper outstanding at 31 March 2025. In addition, the company has drawings of CAD211 million available on a facility from the Canada Infrastructure Bank to support SMR investments that expires in September 2027, CAD750 million undrawn on a facility with the OEFC that expires in December 2026 and CAD1,250 million undrawn on a facility with the Ontario Financing Authority that expire in December 2029.

The company has asset level facilities of CAD460 million committed at Lower Mattagami Energy Limited Partnership that expires in June 2029 and a USD20 million committed facility at OPG Eagle Creek Holdings LLC and subsidiaries that combined supported letters of credit of about CAD79 million. We have conservatively assumed that letters of credit of CAD431 million that are not allocated to above listed credit facilities are supported by corporate facilities and are reflected in our calculations of available credit facilities.

Moody's forecasts cash flow from operations over the next twelve months to be around CAD3.1 billion. In addition to the available credit facilities of CAD3.6 billion and cash and cash equivalents including restricted cash of around CAD2.6 billion as of 31 March 2025, these sources should be sufficient to cover uses comprising CAD5-6 billion of expected capital expenditures and around CAD600 million of debt maturities in the next 12 months. We expect OPG will rely in part on debt to finance its ongoing capex and refinance its upcoming debt maturities. The company's liquidity position benefits from the lack of regular dividends payable to the Province.

There are material adverse change clauses in its credit facilities that could prevent borrowings under certain circumstances, a credit and liquidity negative. Moody's expects the company to manage its program maturities, cash on hand and its swing lines in a prudent fashion.

Rating methodology and scorecard factors

The principal methodology used for this rating is the Regulated Electric and Gas Utilities rating methodology. The scorecard- indicated outcome for our 12-18 months forward view is Baa1, two notches above the BCA of baa3 with the difference attributable to elevated capex risk and OPG's generation asset base compared to all peers having at least some lower risk transmission and distribution assets.

Exhibit 8

Methodology scorecard factors

Ontario Power Generation Inc.

Regulated Electric and Gas Utilities Industry Scorecard	Current FY Dec-24		Moody's 12-18 Month Forward View	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	Baa	Baa	Baa	Baa
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Baa	Baa	Baa	Baa
b) Sufficiency of Rates and Returns	Ba	Ba	Ba	Ba
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	A	A	A	A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	6.4x	Aa	5x - 7x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	21.2%	Baa	15% - 20%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	21.1%	A	15% - 20%	A
d) Debt / Capitalization (3 Year Avg)	33.8%	Aa	35% - 40%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		Baa1		Baa1
HoldCo Structural Subordination Notching		0		0
a) Scorecard-Indicated Outcome		Baa1		Baa1
b) Actual Rating Assigned		A3		A3
Government-Related Issuer		**Factor**		
a) Baseline Credit Assessment		baa3		
b) Government Local Currency Rating		Aa3		
c) Default Dependence		High		
d) Support		High		
e) Actual Rating Assigned		A3		

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. Moody's forecasts are Moody's opinion and do not represent the views of the issuer.

Sources: Moody's Financial Metrics™ and Moody's Ratings forecasts

Appendix

Exhibit 9

Peer comparison

Ontario Power Generation Inc.

	Ontario Power Generation Inc. A3 Stable			NextEra Energy, Inc. Baa1 Stable		
(In $ millions)	FY Dec-23	FY Dec-24	LTM Mar-25	FY Dec-23	FY Dec-24	LTM Mar-25
Revenue	5,510	5,248	5,448	28,114	24,753	25,269
CFO Pre-W/C	1,877	1,560	1,762	11,439	12,269	12,591
Total Debt	8,729	8,625	9,711	72,206	80,599	86,694
CFO Pre-W/C + Interest / Interest	7.2x	5.6x	6.2x	4.2x	5.9x	4.2x
CFO Pre-W/C / Debt	22.0%	17.2%	17.5%	15.8%	15.2%	14.5%
CFO Pre-W/C – Dividends / Debt	21.8%	17.1%	17.4%	10.5%	9.8%	9.3%
Debt / Capitalization	33.7%	34.0%	36.2%	50.5%	51.8%	53.4%

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Source: Moody's Financial Metrics™

Exhibit 10

Moody's – adjusted cash flow metrics

Ontario Power Generation Inc.

(In $ millions)	2020	2021	2022	2023	2024	LTM Mar-25
FFO	**2,538.3**	**2,231.0**	**2,471.0**	**2,590.0**	**2,024.0**	**2,276.0**
+/- Other	81.0	68.0	178.0	(57.0)	112.0	174.0
CFO Pre-WC	**2,619.3**	**2,299.0**	**2,649.0**	**2,533.0**	**2,136.0**	**2,450.0**
+/- ΔWC	103.0	59.0	223.0	(114.0)	(61.0)	(185.0)
CFO	**2,722.3**	**2,358.0**	**2,872.0**	**2,419.0**	**2,075.0**	**2,265.0**
- Div	19.0	19.0	17.0	19.0	19.0	18.0
- Capex	1,663.3	1,943.0	2,432.0	2,782.0	3,401.0	3,803.0
FCF	**1,040.0**	**396.0**	**423.0**	**(382.0)**	**(1,345.0)**	**(1,556.0)**
(CFO Pre-W/C) / Debt	17.0%	18.1%	25.2%	22.0%	17.2%	17.5%
(CFO Pre-W/C - Dividends) / Debt	16.8%	17.9%	25.0%	21.8%	17.1%	17.4%
FFO / Debt	16.4%	17.6%	23.5%	22.5%	16.3%	16.3%
RCF / Debt	16.3%	17.4%	23.3%	22.3%	16.2%	16.2%
Revenue	7,240.0	6,877.0	7,349.0	7,434.0	7,187.0	7,577.0
Interest Expense	514.0	478.6	482.0	411.6	463.9	473.4
Net Income	1,073.8	981.5	1,132.6	1,448.9	697.8	982.4
Total Assets	61,961.0	61,071.0	62,218.0	65,569.0	68,840.0	71,253.0
Total Liabilities	46,694.4	44,351.6	43,508.5	45,261.2	47,337.0	49,255.0
Total Equity	15,266.6	16,719.4	18,709.5	20,307.9	21,503.0	21,998.0

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Periods are fiscal year-end unless indicated.
Source: Moody's Financial Metrics™

Exhibit 11

Moody's – adjusted Debt reconciliation

Ontario Power Generation Inc.

(In $ millions)	2020	2021	2022	2023	2024	LTM Mar-25
As reported debt	**10.4**	**9.8**	**10.2**	**10.5**	**11.9**	**13.5**
Pensions	5.0	2.9	0.3	0.9	0.4	0.4
Operating Leases	0.0	-	-	0.1	0.1	0.1
Moody's – adjusted debt	**15.5**	**12.7**	**10.5**	**11.5**	**12.4**	**14.0**

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Periods are fiscal year-end unless indicated.
Source: Moody's Financial Metrics™

Exhibit 12

Moody's – adjusted EBITDA reconciliation

Ontario Power Generation Inc.

(In $ millions)	2020	2021	2022	2023	2024	LTM Mar-25
As reported EBITDA	3.0	2.9	3.4	3.6	2.8	3.3
Pensions	(0.2)	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)
Operating Leases	0.0	-	-	-	-	-
Unusual	-	(0.1)	(0.1)	-	-	-
Moody's – adjusted EBITDA	2.9	2.7	3.0	3.4	2.6	3.0

All figures and ratios are based on adjusted financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
Periods are fiscal year-end unless indicated.
Source: Moody's Financial Metrics™

Ratings

Exhibit 13

Category	Moody's Rating
ONTARIO POWER GENERATION INC.	
Outlook	Stable
Senior Unsecured -Dom Curr	A3
Commercial Paper	P-2

Source: Moody's Ratings

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Ontario Power Generation Inc.

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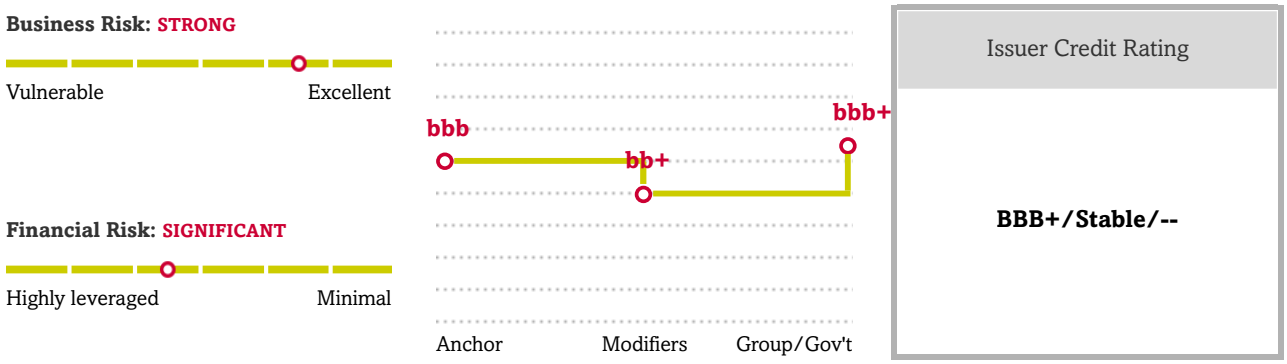
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Ontario Power Generation Inc.



Credit Highlights

Overview

Key strengths	Key risks
Lower-risk, rate-regulated utility operations.	Limited geographical and regulatory diversity.
Diverse portfolio of power-generating assets.	Refurbishment of legacy nuclear generation plants exposes company to execution risks.
High likelihood of extraordinary government support.	

The Darlington Nuclear Plant refurbishment project exposes Ontario Power Generation Inc. (OPG) to execution risk. The refurbishment project that started in 2016 is still in progress and has remained on course for timely completion, even with a slight delay of Unit 3 due to COVID-19. OPG expects to complete the project within the C$12.8 billion budget. Any material cost overruns could weaken credit measures.

Regulatory approval of hydroelectric base regulated prices for the 2021-2026 period will provide consistent cash flow without major deviations from the current trend. The Ontario Energy Board (OEB) approved the annual formulaic adjustment to increase the base regulated price for OPG's regulated hydroelectric facilities for the year 2021 and set OPG's hydroelectric base regulated price from January 1, 2022, through Dec. 31, 2026, equal to the 2021 hydroelectric base regulated rate. The rate base approved is similar to current trends and does not affect the revenue trend of OPG's hydroelectric segment. This will help OPG maintain stable cash flows through the approved periods.

Deferral of planned maintenance outages and refurbishment delays caused by COVID-19 had a positive effect on 2020 financial results. In 2020, due to COVID-19, OPG's financial measures strengthened from maintenance deferrals, reducing operating expenses, and the Darlington refurbishment delay, increasing electricity production. In addition, the recently acquired natural gas fleet at Atura Power added to generation output and cash flow. Financial metrics also benefited from higher regulated rates.

OPG continues to invest in its nuclear generation. In addition to the Darlington refurbishment project, OPG is working on installing small modular nuclear reactors at Darlington.

Outlook: Stable

The stable outlook incorporates our view for more stable cash flows, reflecting our expectations that the company will pause on its acquisition strategy, continue to effectively manage regulatory risk, and our increased confidence that future nuclear refurbishments will be completed on time and on budget. We also expect funds from operations (FFO) to debt of 13%-15%.

Downside scenario

We could take a negative rating action on OPG over the next 12-18 months if the company's financial measures weaken, reflecting FFO to debt consistently below 13%. This could happen if the company experiences delay and cost overruns at its Darlington refurbishment program, adverse regulatory decisions, or significant debt-funded acquisitions. Alternatively, a downgrade to the Province of Ontario or an unexpected deterioration in the relationship between OPG and the province could also result in a negative rating action.

Upside scenario

Although highly unlikely, we could take a positive rating action on OPG over the next 24 months if there is no change to the company's relationship with the Province of Ontario, the company's nonutility businesses do not grow through additional acquisitions, and the company's financial measures materially improve, reflecting FFO to debt consistently greater than 20%.

Our Base-Case Scenario

Assumptions

- OPG will continue to focus on regulated electricity generation businesses in Ontario.
- Annual capital spending of about C$2.4 billion per year in 2021-2023.
- Dividend payments averaging about C$20 million per year in 2021-2023.
- Consistent base regulated prices for hydroelectric generation for the 2022-2026 period.
- No material acquisitions.
- All debt maturities are refinanced.

Key metrics

Ontario Power Generation Inc.--Key Metrics

	2021e	2022f	2023f
FFO to debt (%)	13-15	12-14	12-14
Debt to EBITDA (x)	6-6.6	6-6.6	6-6.6

Ontario Power Generation Inc.--Key Metrics (cont.)

	2021e	2022f	2023f
FFO cash interest coverage (x)	6-6.5	6-6.5	5.5-6

e--Estimated. f--Forecast. FFO--Funds from operations.

Company Description

OPG is an Ontario-based electricity generation company. OPG's generation fleet has about 18,900 megawatts (MW) of capacity. OPG is wholly owned by the Province of Ontario.

Peer Comparison

Table 1

Ontario Power Generation Inc.--Peer Comparison

Industry Sector: Electric

	Ontario Power Generation Inc.	Hydro One Inc.	ENMAX Corp.	ATCO Ltd.
Ratings as of July 28, 2021	BBB+/Stable/--	A-/Stable/A-2	BBB-/Negative/--	A-/Negative/--
	--Fiscal year ended Dec. 31, 2020--			
(Mil. C$)				
Revenue	7,240.0	7,250.0	2,626.2	3,944.0
EBITDA	3,412.0	2,377.0	680.6	1,712.0
Funds from operations (FFO)	2,779.1	1,837.1	510.4	1,236.5
Interest expense	417.9	515.0	172.9	465.5
Cash interest paid	391.9	507.0	156.7	444.5
Cash flow from operations	2,722.1	1,946.1	546.0	1,359.5
Capital expenditure	1,653.0	1,786.0	449.1	1,015.0
Free operating cash flow (FOCF)	1,069.1	160.1	96.9	344.5
Discretionary cash flow (DCF)	1,050.1	(450.0)	42.9	(142.0)
Cash and short-term investments	889.0	712.0	27.9	1,064.0
Debt	15,814.0	15,952.5	4,381.2	9,835.3
Equity	15,532.0	10,898.0	2,416.5	7,114.0
Adjusted ratios				
EBITDA margin (%)	47.1	32.8	25.9	43.4
Return on capital (%)	7.2	5.8	6.2	6.5
EBITDA interest coverage (x)	8.2	4.6	3.9	3.7
FFO cash interest coverage (x)	8.1	4.6	4.3	3.8
Debt/EBITDA (x)	4.6	6.7	6.4	5.7
FFO/debt (%)	17.6	11.5	11.6	12.6
Cash flow from operations/debt (%)	17.2	12.2	12.5	13.8
FOCF/debt (%)	6.8	1.0	2.2	3.5
DCF/debt (%)	6.6	(2.8)	1.0	(1.4)

Business Risk: Strong

A strong business risk profile reflects our expectations for more stable and predictable cash flows. The business risk profile is supported by the company's regulated operation that constitutes about 70% of consolidated EBITDA and is regulated by the OEB. The company benefits from the generally supportive regulatory environment that includes using an incentive ratemaking methodology for hydroelectric and a custom incentive regulation framework for nuclear. In addition, the company uses various regulatory mechanisms, which smooth cash flow and we view as supportive of credit quality.

The business risk profile is affected by the company's growing contracted nonregulated generation, which will contribute about 30% of consolidated EBITDA. The contracted nonregulated power business increases the company's volumetric, operational, and commodity risks. These risks are partially offset by the business' long-term contracts with creditworthy counterparties. Because of OPG's nonregulated power exposure, we assess the company at the lower end of the range for its business risk profile category, as compared to peers.

Financial Risk: Significant

Under our base-case scenario, which assumes capital spending averaging about C$2.4 billion per year and dividend payments of about C$20 million, we expect FFO to debt of about 13%-15% in 2021. This measure weakens into the 12%-14% range in 2022 and 2023 due to the refurbishment of multiple units at the Darlington Station. We also anticipate that OPG's adjusted debt to EBITDA will average in the 6x-6.6x range over the next few years. Over the same period, our supplemental ratio of adjusted FFO cash interest coverage will be about 5.5x-6.5x, bolstering our financial risk profile assessment. We do not expect material negative discretionary cash flow in the next few years, limiting external funding needs that could include debt issuances. We base our assessment on our medial-volatility table financial benchmarks, reflecting the company's lower-risk regulated electric generation operations and effective management of regulatory risk. These benchmarks are more relaxed than those we use for typical corporate issuers.

Financial summary

Table 2

Ontario Power Generation Inc.--Financial Summary

Industry Sector: Electric

	--Fiscal year ended Dec. 31--				
	2020	**2019**	**2018**	**2017**	**2016**
(Mil. C$)					
Revenue	7,240.0	6,022.0	5,474.0	5,144.1	5,653.0
EBITDA	3,412.0	2,460.0	2,019.0	1,609.1	2,225.0
Funds from operations (FFO)	2,779.1	1,860.2	1,530.4	1,159.2	1,849.3
Interest expense	417.9	346.8	277.7	292.9	351.7
Cash interest paid	391.9	299.8	286.6	254.9	277.7
Cash flow from operations	2,722.1	2,399.2	1,510.4	797.2	1,575.3

Table 2

Ontario Power Generation Inc.--Financial Summary (cont.)

Industry Sector: Electric

	--Fiscal year ended Dec. 31--				
	2020	**2019**	**2018**	**2017**	**2016**
Capital expenditure	1,653.0	1,837.0	1,635.0	1,691.0	1,563.0
Free operating cash flow (FOCF)	1,069.1	562.2	(124.6)	(893.8)	12.3
Discretionary cash flow (DCF)	1,050.1	545.2	(425.6)	(908.8)	(1.7)
Cash and short-term investments	889.0	648.0	349.0	418.0	186.0
Gross available cash	889.0	648.0	349.0	418.0	398.0
Debt	15,814.0	13,175.0	11,437.4	10,583.2	9,706.9
Equity	15,532.0	14,275.0	13,127.0	11,911.0	10,508.0
Adjusted ratios					
EBITDA margin (%)	47.1	40.9	36.9	31.3	39.4
Return on capital (%)	7.2	5.4	5.2	4.4	5.0
EBITDA interest coverage (x)	8.2	7.1	7.3	5.5	6.3
FFO cash interest coverage (x)	8.1	7.2	6.3	5.5	7.7
Debt/EBITDA (x)	4.6	5.4	5.7	6.6	4.4
FFO/debt (%)	17.6	14.1	13.4	11.0	19.1
Cash flow from operations/debt (%)	17.2	18.2	13.2	7.5	16.2
FOCF/debt (%)	6.8	4.3	(1.1)	(8.4)	0.1
DCF/debt (%)	6.6	4.1	(3.7)	(8.6)	(0.0)

Reconciliation

Table 3

Ontario Power Generation Inc.--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts

	--Fiscal year ended Dec. 31, 2020--							
Ontario Power Generation Inc. reported amounts (mil. C$)								
	Debt	**Shareholders' equity**	**EBITDA**	**Operating income**	**Interest expense**	**S&P Global Ratings' adjusted EBITDA**	**Cash flow from operations**	**Capital expenditure**
	10,382.0	15,354.0	3,398.0	2,076.0	304.0	3,412.0	2,824.0	1,765.0
S&P Global Ratings' adjustments								
Cash taxes paid	--	--	--	--	--	(241.0)	--	--
Cash interest paid	--	--	--	--	--	(278.0)	--	--
Reported lease liabilities	47.0	--	--	--	--	--	--	--
Operating leases	--	--	12.0	1.9	1.9	(1.9)	10.1	--
Postretirement benefit obligations/deferred compensation	6,274.0	--	--	--	--	--	--	--
Accessible cash and liquid investments	(889.0)	--	--	--	--	--	--	--
Capitalized interest	--	--	--	--	112.0	(112.0)	(112.0)	(112.0)

Table 3

Ontario Power Generation Inc.--Reconciliation Of Reported Amounts With S&P Global Ratings' Adjusted Amounts (cont.)								
Dividends received from equity investments	--	--	13.0	--	--	--	--	--
Income (expense) of unconsolidated companies	--	--	(11.0)	--	--	--	--	--
Nonoperating income (expense)	--	--	--	45.0	--	--	--	--
Noncontrolling interest/minority interest	--	178.0	--	--	--	--	--	--
Total adjustments	5,432.0	178.0	14.0	46.9	113.9	(632.9)	(101.9)	(112.0)

S&P Global Ratings' adjusted amounts

	Debt	Equity	EBITDA	EBIT	Interest expense	Funds from operations	Cash flow from operations	Capital expenditure
	15,814.0	15,532.0	3,412.0	2,122.9	417.9	2,779.1	2,722.1	1,653.0

Liquidity: Adequate

We assess OPG's liquidity as adequate because we believe its liquidity sources are likely to cover uses by more than 1.1x over the next 12 months and meet cash outflows even with a 10% decline in EBITDA. Moreover, liquidity should benefit from the company's likely ability to absorb high-impact, low-probability events without the need for refinancing, its well-established and solid relationships with banks, and its satisfactory standing in the credit markets.

Principal liquidity sources

- Cash and liquid investments of about C$835 million
- Average credit facility availability of C$ 1.425 billion
- Estimated cash FFO of about C$2.5 billion

Principal liquidity uses

- Debt maturities of about C$1.5 billion
- Capital spending of C$2.5 billion
- Dividends of about C$20 million

Debt maturities

- 2021: C$439 million
- 2022: C$206 million
- 2023: C$73 million
- 2024: C$616 million
- 2025: C$579 million

Environmental, Social, And Governance

The company's current generation capacity of about 18,900 MW consists of 30% regulated nuclear, 34% regulated hydroelectric, 14% contracted gas, and about 22% contracted hydroelectric and others. OPG has released a climate change plan that outlines the company's sustainability goals. The plan aims to achieve net-zero carbon emissions by 2040 through technologies such as small modular reactors, hydro upgrades, electrification, nuclear refurbishment, and nature-based solutions. OPG's social and governance factors are in line with those of other regulated utilities.

Group Influence

Our ratings on OPG incorporate a high likelihood that OPG's provincial owner, the Government of Ontario, will provide extraordinary support to the utility during periods of financial distress. OPG plays an important role to Ontario because it supplies about half of the province's electricity. In addition, the utility plays a vital role to Ontario's energy and environmental policies. Furthermore, the province has a record of providing support, both directly and indirectly, to the utility. For these reasons, we view the likelihood of extraordinary government support for OPG as high.

Issue Ratings - Subordination Risk Analysis

Capital structure

OPG's capital structure consists of roughly C$10 billion in debt.

Analytical conclusions

We rate the senior unsecured debt the same as the issuer credit rating on OPG because priority debt is less than 50% of total consolidated debt. We also rate OPG's commercial paper at 'A-1(Low)' on the Canadian National Scale.

Ratings Score Snapshot

Issuer Credit Rating

BBB+/Stable/--

Business risk: Strong

- **Country risk:** Very low
- **Industry risk:** Low
- **Competitive position:** Strong

Financial risk: Significant

- **Cash flow/leverage:** Significant

Anchor: bbb

Modifiers

- **Diversification/portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Negative (-1 notch)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Negative (-1 notch)

Stand-alone credit profile : bb+

- **Related government rating:** A+
- **Likelihood of government support:** High (+3 notches from SACP)

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria | Corporates | Industrials: Key Credit Factors For The Unregulated Power And Gas Industry, March 28, 2014
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- ARCHIVE | General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Business And Financial Risk Matrix

Business Risk Profile	Financial Risk Profile					
	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	**bbb**	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Ratings Detail (As Of August 13, 2021)*

Ontario Power Generation Inc.	
Issuer Credit Rating	BBB+/Stable/--
Commercial Paper	
Canada National Scale Commercial Paper	A-1(LOW)
Senior Unsecured	BBB+
Issuer Credit Ratings History	
17-Jul-2020	BBB+/Stable/--
30-Jul-2019	BBB+/Negative/--
07-Jul-2015	BBB+/Stable/--

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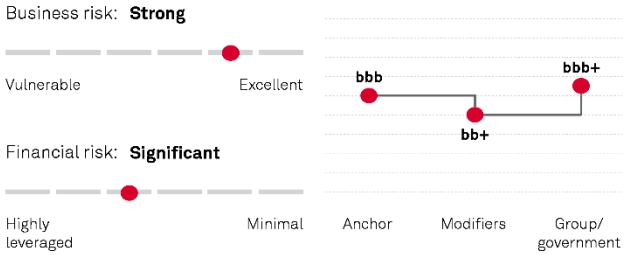
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Ontario Power Generation Inc.

August 3, 2022

Ratings Score Snapshot



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Credit Highlights

Overview

Key strengths	Key risks
Lower-risk, rate-regulated utility operations.	Limited geographic and regulatory diversity.
Diverse portfolio of power-generating assets.	Refurbishment of legacy nuclear generation plant exposes it to execution risk.
High likelihood of extraordinary government support.	Robust capital spending leads to negative discretionary cash flow, indicating a need for external funding.

Ontario Power Generation Inc. (OPG) is exposed to execution risks stemming from the refurbishment of the Darlington Nuclear Plant. It expects to refurnish all four units by the end of 2026. The refurbishment project, which began in 2016, is still in progress and remains on track for a timely completion despite a slight delay due to COVID-19. The refurbishment of Unit 2 was completed in June 2020 while the remaining units are still in progress. OPG expects Unit 3, Unit 1, and Unit 4 to be in service by 2024, 2025, and 2026, respectively. We expect the company to assess and seek ways to manage the effects of the COVID-19 pandemic on the project's total cost, which is otherwise continuing to track in-line the $12.8 billion budget. Any material cost overruns would pressure OPG's credit measures.

We expect OPG will continue to manage its regulatory risk and maintain financial measures in the lower half of our significant financial risk profile category. Specifically, we expect the company's funds from operations (FFO) to debt will be in the 13.0%-15.5% range throughout the forecast period.

Outlook

The stable outlook on OPG incorporates our expectation for more stable cash flows, our belief that it has paused its acquisition spending and continues to effectively manage its regulatory risk, as well as our expectation that it will complete its future nuclear refurbishments on time and on budget. We also forecast FFO to debt of 13.0%-15.5%.

Downside scenario

We could take a negative rating action on OPG over the next 12-18 months if its financial measures weaken, including FFO to debt of consistently below 13%. This could occur if the company experiences delay and cost overruns in its Darlington refurbishment program and adverse regulatory decisions or undertakes significant debt-funded acquisitions. Alternatively, we could lower our rating if we downgrade the Province of Ontario or there is an unexpected deterioration in the relationship between OPG and the province.

Upside scenario

Although highly unlikely, we could take a positive rating action on OPG over the next 24 months if there is no change to its relationship with the Province of Ontario, it doesn't expand its nonutility businesses through acquisitions, and it materially improves its financial measures, including FFO to debt of consistently more than 20%.

Our Base-Case Scenario

Assumptions

- OPG will continue to manage its regulatory risk;
- Capital spending averaging C$3.2 billion-C$3.6 billion per year through 2024;
- Dividend payments averaging about C$20 million per year;
- No material acquisitions; and
- All debt maturities are refinanced or repaid.

Key metrics

Ontario Power Generation Inc.--Key Metrics*

	2021a	2022e	2023f
FFO to debt (%)	17.7	14-15	15-16
Debt to EBITDA (x)	4.6	5.5-6.0	5.0-5.5

*All figures adjusted by S&P Global Ratings. a--Actual. e--Estimate. f--Forecast. FFO--Funds from operations.

Company Description

OPG is an Ontario-based electricity generation company. The company's generation fleet comprises about 18,100 megawatts (MW) of capacity. OPG is wholly owned by the Province of Ontario.

Peer Comparison

Ontario Power Generation Inc.--Peer Comparisons

	Ontario Power Generation Inc.	Hydro One Inc.	ENMAX Corp.	ATCO Ltd.
Foreign currency issuer credit rating	BBB+/Stable/--	A-/Stable/A-2	BBB-/Negative/--	BBB+/Stable/--
Local currency issuer credit rating	BBB+/Stable/--	A-/Stable/A-2	BBB-/Negative/--	BBB+/Stable/--
Period	Annual	Annual	Annual	Annual
Period ending	2021-12-31	2021-12-31	2021-12-31	2021-12-31
Mil.	C$	C$	C$	C$
Revenue	6,877	7,185	3,097	4,289
EBITDA	2,944	2,539	668	1,745
Funds from operations (FFO)	2,400	2,010	528	1,263
Interest	383	515	158	462
Cash interest paid	371	509	167	432
Operating cash flow (OCF)	2,358	2,052	633	1,313
Capital expenditure	1,943	1,990	513	1,340
Free operating cash flow (FOCF)	415	62	120	(28)
Discretionary cash flow (DCF)	396	(566)	62	(733)
Cash and short-term investments	868	499	41	1,073
Gross available cash	868	499	41	1,073
Debt	13,582	15,779	4,254	10,113
Equity	16,967	11,260	2,715	7,169
EBITDA margin (%)	42.8	35.3	21.6	40.7
Return on capital (%)	6.0	6.1	4.9	6.2
EBITDA interest coverage (x)	7.7	4.9	4.2	3.8
FFO cash interest coverage (x)	7.5	5.0	4.2	3.9
Debt/EBITDA (x)	4.6	6.2	6.4	5.8
FFO/debt (%)	17.7	12.7	12.4	12.5
OCF/debt (%)	17.4	13.0	14.9	13.0
FOCF/debt (%)	3.1	0.4	2.8	(0.3)

Ontario Power Generation Inc.--Peer Comparisons

DCF/debt (%)	2.9	(3.6)	1.5	(7.2)

Business Risk

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 that OPG will continue to manage its regulatory risk and benefit from credit-supportive regulatory mechanisms, including an incentive ratemaking methodology for hydroelectric and a custom incentive regulation framework for nuclear.

Our assessment of OPG's business risk profile also incorporates its growing contracted nonregulated generation, which will account for about 30% of its consolidated EBITDA. The contracted nonregulated power business increases the company's volumetric, operational, and commodity risks. However, these risks are partially offset by the business' long-term contracts with creditworthy counterparties. Given OPG's nonregulated power exposure, we assess it as being at the lower end of the range for its business risk profile category when compared with its peers. In addition, the company is exposed to execution risks related to its Darlington Nuclear Plant refurbishment project.

Financial Risk

We use our medial-volatility table financial benchmarks to assess OPG's financial risk, which reflects its lower-risk regulated electric generation operations and effective management of regulatory risk. These benchmarks are more relaxed than the benchmarks we use for typical corporate issuers. Under our base-case scenario, we assume capital spending averaging of C$3.2 billion-C$3.6 billion per year through 2024 and dividends of about C$20 million per year. We also expect OPG's discretionary cash flow will remain negative due to its elevated capital spending, indicating a need for external funding. In addition, we forecast the company's FFO to debt will be in the 13.0%-15.5% range throughout our forecast period. Over the same period, we anticipate its S&P Global Ratings-adjusted FFO cash interest coverage will be in the 5.0x-6.0x range, which further bolsters our financial risk profile assessment.

Debt maturities

- 2022: C$179 million;
- 2023: C$44 million;
- 2024: C$607 million;
- 2025: C$579 million;
- 2026: C$675 million; and
- Thereafter: C$7.6 billion.

Ontario Power Generation Inc.--Financial Summary

Period ending	Dec-31-2016	Dec-31-2017	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021
Reporting period	2016a	2017a	2018a	2019a	2020a	2021a
Display currency (mil.)	C$	C$	C$	C$	C$	C$

Ontario Power Generation Inc.--Financial Summary

Revenues	5,653	5,144	5,474	6,022	7,240	6,877
EBITDA	2,225	1,609	2,019	2,460	3,412	2,944
Funds from operations (FFO)	1,849	1,159	1,530	1,860	2,779	2,400
Interest expense	352	293	278	347	418	383
Cash interest paid	278	255	287	300	392	371
Operating cash flow (OCF)	1,575	797	1,510	2,399	2,722	2,358
Capital expenditure	1,563	1,691	1,635	1,837	1,653	1,943
Free operating cash flow (FOCF)	12	(894)	(125)	562	1,069	415
Discretionary cash flow (DCF)	(2)	(909)	(426)	545	1,050	396
Cash and short-term investments	186	418	349	648	889	868
Gross available cash	398	418	349	648	889	868
Debt	9,707	10,583	11,437	13,175	15,814	13,582
Common equity	10,508	11,911	13,127	14,275	15,532	16,967
Adjusted ratios						
EBITDA margin (%)	39.4	31.3	36.9	40.9	47.1	42.8
Return on capital (%)	5.0	4.4	5.2	5.4	7.2	6.0
EBITDA interest coverage (x)	6.3	5.5	7.3	7.1	8.2	7.7
FFO cash interest coverage (x)	7.7	5.5	6.3	7.2	8.1	7.5
Debt/EBITDA (x)	4.4	6.6	5.7	5.4	4.6	4.6
FFO/debt (%)	19.1	11.0	13.4	14.1	17.6	17.7
OCF/debt (%)	16.2	7.5	13.2	18.2	17.2	17.4
FOCF/debt (%)	0.1	(8.4)	(1.1)	4.3	6.8	3.1
DCF/debt (%)	(0.0)	(8.6)	(3.7)	4.1	6.6	2.9

Reconciliation Of Ontario Power Generation Inc. Reported Amounts With S&P Global Adjusted Amounts (Mil. C$)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2021									
Company reported amounts	9,848	16,789	6,877	2,945	1,813	301	2,944	2,440	19	2,025
Cash taxes paid	-	-	-	-	-	-	(173)	-	-	-
Cash interest paid	-	-	-	-	-	-	(289)	-	-	-
Lease liabilities	50	-	-	-	-	-	-	-	-	-

Reconciliation Of Ontario Power Generation Inc. Reported Amounts With S&P Global Adjusted Amounts (Mil. C$)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Postretirement benefit obligations/ deferred compensation	4,552	-	-	-	-	-	-	-	-	-
Accessible cash and liquid investments	(868)	-	-	-	-	-	-	-	-	-
Capitalized interest	-	-	-	-	-	82	(82)	(82)	-	(82)
Income (expense) of unconsolid. cos.	-	-	-	(1)	-	-	-	-	-	-
Nonoperating income (expense)	-	-	-	-	39	-	-	-	-	-
Noncontrolling/ minority interest	-	178	-	-	-	-	-	-	-	-
Total adjustments	3,734	178	-	(1)	39	82	(544)	(82)	-	(82)
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	13,582	16,967	6,877	2,944	1,852	383	2,400	2,358	19	1,943

Liquidity

We assess OPG's liquidity as adequate because we believe its liquidity sources will likely be more than 1.1x its uses over the next 12 months and meet its cash outflows even if its EBITDA declines by 10%. Moreover, we anticipate the company would likely be able to absorb high-impact, low-probability events without needing to refinance and view it as having well-established and solid relationships with its banks and a satisfactory standing in the credit markets.

Principal liquidity sources

- Cash and liquid investments of about C$935 million;
- Average credit facility availability of C$2.15 billion; and
- Estimated cash FFO of about C$2.45 billion.

Principal liquidity uses

- Debt maturities of about C$335 million;
- Capital spending of C$3.3 billion; and
- Dividends of about C$20 million.

Environmental, Social, And Governance

ESG Credit Indicators

E-1	E-2	**E-3**	E-4	E-5	S-1	S-2	**S-3**	S-4	S-5	G-1	**G-2**	G-3	G-4	G-5
- Natural capital - Waste and pollution					- Health and safety					- N/A				

N/A--Not applicable. ESG credit indicators provide additional disclosure and transparency at the entity level and reflect S&P Global Ratings ' opinion of the influence that environmental, social, and governance factors have on our credit rating analysis. They are not a sustainability rating or an S&P Global Ratings ESG Evaluation. The extent of the influence of these factors is reflected on an alphanumerical 1 - 5 scale where 1 = positive, 2 = neutral, 3 = moderately negative, 4 = negative, and 5 = very negative. For more information, see our commentary " ESG Credit Indicators: Definition And Applications, " published Oct. 13, 2021.

Environmental factors are a moderately negative consideration in our credit rating analysis of Ontario Power Generation Inc. because it has a consolidated exposure to nuclear and hydro generation. The company's nuclear generation exposes it to waste and storage challenges while its hydro generation exposes it to water resource use. Social factors are a moderately negative consideration in our credit rating analysis based on the health and safety risks related to its nuclear generation.

Group Influence

Our ratings on OPG incorporate a high likelihood that its provincial owner, the Government of Ontario, will provide extraordinary support to the utility during periods of financial distress. OPG plays an important role for Ontario because it supplies about half of the province's electricity. In addition, the utility plays a vital role in Ontario's energy and environmental policies. Furthermore, the province has a record of providing support, both directly and indirectly, to the utility. For these reasons, we view the likelihood of extraordinary government support as high.

Issue Ratings--Subordination Risk Analysis

Capital structure

OPG's capital structure comprises roughly C$10 billion of debt.

Analytical conclusions

We rate the company's senior unsecured debt at the same level as our issuer credit rating because its priority debt is less than 50% of its total consolidated debt. We also rate OPG's commercial paper at 'A-1(Low)' on the Canadian National Scale.

Rating Component Scores

Foreign currency issuer credit rating	**BBB+/Stable/--**
Local currency issuer credit rating	**BBB+/Stable/--**
Business risk	**Strong**
Country risk	Very Low
Industry risk	Low
Competitive position	Strong
Financial risk	**Significant**
Cash flow/leverage	Significant
Anchor	**bbb**
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Negative (-1 notch)
Liquidity	Adequate (no impact)
Management and governance	Satisfactory (no impact)
Comparable rating analysis	Negative (-1 notch)
Stand-alone credit profile	**bb+**

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria | Corporates | Industrials: Key Credit Factors For The Unregulated Power And Gas Industry, March 28, 2014
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- ARCHIVE | General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Ratings Detail (as of August 03, 2022)*

Ontario Power Generation Inc.	
Issuer Credit Rating	BBB+/Stable/--
Commercial Paper	
Canada National Scale Commercial Paper	A-1(LOW)

Ratings Detail (as of August 03, 2022)*

Senior Unsecured	BBB+

Issuer Credit Ratings History

17-Jul-2020	BBB+/Stable/--
30-Jul-2019	BBB+/Negative/--
07-Jul-2015	BBB+/Stable/--

Related Entities

Hydro One Inc.

Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Canada National Scale Commercial Paper	A-1(LOW)
Senior Unsecured	A-

Hydro One Ltd.

Issuer Credit Rating	A-/Stable/--
Senior Unsecured	BBB+

Ontario (Province of)

Issuer Credit Rating	A+/Stable/A-1
Commercial Paper	
Foreign Currency	A-1
Senior Unsecured	A+

UMH Energy Partnership

Senior Secured	BBB+/Stable

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings credit ratings on the global scale are comparable across countries. S&P Global Ratings credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

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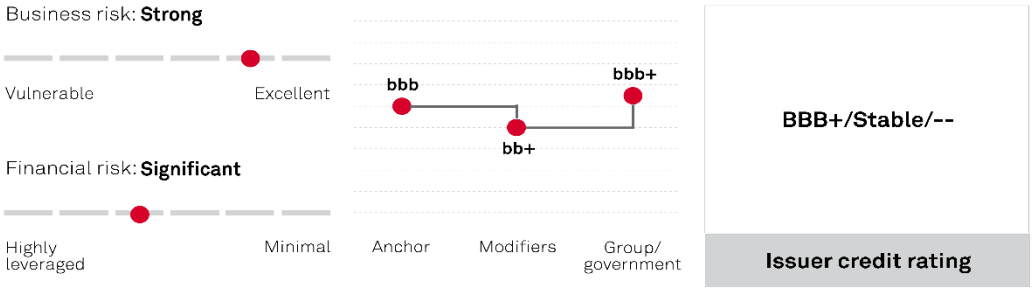
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Ontario Power Generation Inc.

August 8, 2023

Ratings Score Snapshot



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Credit Highlights

Overview

Key strengths	Key risks
Lower-risk, rate-regulated utility operations.	Limited geographic and regulatory diversity.
Diverse portfolio of power-generating assets.	Refurbishment of legacy nuclear generation plant exposes it to execution risk.
High likelihood of extraordinary government support.	Robust capital spending leads to negative discretionary cash flow, indicating a need for external funding.

Ontario Power Generation Inc. (OPG) is exposed to execution risks from the refurbishment of the Darlington Nuclear Plant. It expects to refurbish all four units by the end of 2026. The refurbishment project, which began in 2016, is still in progress and remains on track for a timely completion. The company recently announced that it successfully refurbished Darlington Nuclear Generating Station Unit 3 169 days ahead of schedule. This is a major milestone in OPG's nuclear refurbishment project, which it expects will extend the power plant's lifecycle 30 years. Refurbishing the four Darlington units remains on plan for completion by the end of 2026. We expect OPG to assess and seek ways to manage the effects of the COVID-19 pandemic on the project's total cost, which is otherwise still in line with the $12.8 billion budget. Any material

cost overruns would pressure OPG's credit measures. However, the early return of Unit 3 will modestly improve OPG's cash flow.

The ultimate parent of OPG, the Province of Ontario, has directed OPG to conduct a technical feasibility assessment to determine if Pickering Units 5-8 should be refurbished. The province also announced its support for the continued operation of Pickering generating station Units 5-8 up to September 2026 to manage electricity demand growth. We continue to monitor the outcome of the assessment; the current base-case capital forecast does not include any potential investments related to Pickering refurbishment.

The Ontario government and OPG announced the commencement of planning and licensing for three additional small modular reactors (SMRs) at the Darlington nuclear site. The company partnered with GE Hitachi Nuclear Energy, SNC-Lavalin, and Aecon to construct a 300 megawatt (MW) SMR project at the Darlington facility. The Canadian Infrastructure Bank provided a $970 million commitment to fund the project. The company expects to complete the construction of the first unit by the end of 2028. As OPG scales up its investment in SMR projects, it will be highly important that it funds them in a credit-supportive manner and that its recovery is based on rate-regulated mechanisms to preserve its credit quality.

As reported in Canadian popular media, New Brunswick Power Corporation (NB Power) and OPG are exploring a potential partnership that could involve a partial ownership stake in the Point Lepreau nuclear generating station. Since its completed refurbishment in 2012, NB Power's Point Lepreau generating station has been affected by operational challenges, with its most recent December shutdown further adding to the company's debt burden and hurting its profit for fiscal 2022-23. NB Power seeks to leverage OPG's expertise to support the power plant. The effect on OPG's credit quality will largely depend on the details of the potential partnership including, operational involvement, and financial liability related to this nuclear plant. We continue to monitor for further developments.

We expect OPG will continue to manage its regulatory risk and maintain financial measures in the lower half of our significant financial risk profile category. Specifically, we expect funds from operations (FFO) to debt of around 17% in 2023 and 13.0%-14.0% in 2024 and 2025.

Outlook

The stable outlook on OPG incorporates the following expectations: more stable cash flows, a pause in acquisition spending, effective management of its regulatory risk, and that OPG will complete its future nuclear refurbishments on time and on budget. We also forecast FFO to debt of 13.0%-14%.

Downside scenario

We could take a negative rating action on OPG over the next 12-18 months if its financial measures weaken, including FFO to debt consistently below 13%. This could occur if the company experiences delays and cost overruns in its Darlington refurbishment program, faces adverse regulatory decisions, or undertakes significant debt-funded acquisitions. Alternatively, we could lower our rating if we downgrade the Province of Ontario or the relationship between OPG and the province unexpectedly deteriorates.

Upside scenario

Although highly unlikely, we could take a positive rating action on OPG over the next 24 months if there is no change to its relationship with the Province of Ontario, it doesn't expand its nonutility businesses through acquisitions, and it materially improves its financial measures, including FFO to debt consistently more than 20%.

Our Base-Case Scenario

Assumptions

- OPG continues to manage its regulatory risk;
- Capital spending averages C$3.75 billion per year through 2025;
- Distribution to noncontrolling interest holders average about C$20 million per year;
- There are no material acquisitions; and
- All debt maturities are refinanced or repaid.

Key metrics

Ontario Power Generation Inc.--Forecast summary

Period ending	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023	Dec-31-2024	Dec-31-2025	Dec-31-2026
(Mil. CAD)	2019a	2020a	2021a	2022a	2023e	2024f	2025f	2026f
EBITDA	2,460	3,412	2,944	3,161	2,996	2,539	3,086	3,863
Less: Cash interest paid	(300)	(392)	(371)	(359)	(374)	(405)	(464)	(516)
Less: Cash taxes paid	(300)	(241)	(173)	(207)	(260)	(149)	(210)	(327)
Funds from operations (FFO)	1,860	2,779	2,400	2,595	2,362	1,985	2,411	3,020
Capital expenditure (capex)	1,837	1,653	1,943	2,432	3,687	3,721	3,856	4,255
Dividends	17	19	19	17	19	19	19	15
Debt	13,175	15,814	13,582	10,000	13,774	15,438	16,893	18,124
Adjusted ratios								
Debt/EBITDA (x)	5.4	4.6	4.6	3.2	4.6	6.1	5.5	4.7
FFO/debt (%)	14.1	17.6	17.7	25.9	17.1	12.9	14.3	16.7
FFO cash interest coverage (x)	7.2	8.1	7.5	8.2	7.3	5.9	6.2	6.9

All figures are adjusted by S&P Global Ratings, unless stated as reported. a--Actual. e--Estimate. f--Forecast. C$--Canadian dollar.

Company Description

OPG is an Ontario-based electricity generation company. The company's generation fleet comprises about 18,225 MW of capacity. OPG is wholly owned by the Province of Ontario.

Peer Comparison

Ontario Power Generation Inc.--Peer Comparisons

	Ontario Power Generation Inc.	Hydro One Inc.	Enmax Corp.
Foreign currency issuer credit rating	BBB+/Stable/--	A-/Stable/A-2	BBB-/Stable/--
Local currency issuer credit rating	BBB+/Stable/--	A-/Stable/A-2	BBB-/Stable/--
Period	Annual	Annual	Annual
Period ending	2022-12-31	2022-12-31	2022-12-31
Mil.	C$	C$	C$
Revenue	7,349	7,740	3,663
EBITDA	3,161	2,801	719
Funds from operations (FFO)	2,595	2,177	561
Interest	381	525	158
Cash interest paid	359	591	158
Operating cash flow (OCF)	2,872	2,121	716
Capital expenditure	2,432	1,999	581
Free operating cash flow (FOCF)	440	122	135
Discretionary cash flow (DCF)	423	(540)	73
Cash and short-term investments	1,753	458	48
Gross available cash	1,753	458	48
Debt	10,000	15,244	4,120
Equity	18,989	11,682	3,073
EBITDA margin (%)	43.0	36.2	19.6
Return on capital (%)	7.1	6.4	5.2
EBITDA interest coverage (x)	8.3	5.3	4.6
FFO cash interest coverage (x)	8.2	4.7	4.6
Debt/EBITDA (x)	3.2	5.4	5.7
FFO/debt (%)	25.9	14.3	13.6
OCF/debt (%)	28.7	13.9	17.4
FOCF/debt (%)	4.4	0.8	3.3
DCF/debt (%)	4.2	(3.5)	1.8

Business Risk

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 that OPG will continue to manage its regulatory risk and benefit from credit-supportive regulatory

mechanisms, including an incentive ratemaking methodology for hydroelectric and a custom incentive regulation framework for nuclear.

Our assessment of OPG's business risk profile also incorporates its contracted nonregulated generation, which accounts for about 30% of its consolidated EBITDA. The contracted, nonregulated power business increases the company's volumetric, operational, and commodity risks. However, these risks are partially offset by the business' long-term contracts with creditworthy counterparties. Given OPG's nonregulated power exposure, we assess it at the lower end of the range for its business risk profile category compared with its peers. In addition, the company is exposed to execution risks related to its Darlington Nuclear Plant refurbishment project.

Financial Risk

We use our medial-volatility table financial benchmarks to assess OPG's financial risk, which reflects its lower-risk, regulated electric generation operations and effective management of regulatory risk. These benchmarks are more relaxed than the benchmarks we use for typical corporate issuers. Under our base-case scenario, we assume capital spending averaging C$3.75 billion per year through 2025 and dividends of about C$20 million per year. We also expect OPG's discretionary cash flow will remain negative due to its elevated capital spending, indicating a need for external funding. In addition, we forecast FFO to debt around 17% in 2023 and 13.0%-14.0% in 2024 and 2025. Over the same period, we anticipate its S&P Global Ratings-adjusted FFO cash interest coverage will be about 6.0xx, which further bolsters our financial risk profile assessment.

Debt maturities

- 2023: C$43 million;
- 2024: C$606 million;
- 2025: C$589 million;
- 2026: C$674 million;
- 2027: C$530 million; and
- Thereafter: C$7.7 billion.

Ontario Power Generation Inc.--Financial Summary

Period ending	Dec-31-2017	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022
Reporting period	2017a	2018a	2019a	2020a	2021a	2022a
Display currency (mil.)	C$	C$	C$	C$	C$	C$
Revenues	5,144	5,474	6,022	7,240	6,877	7,349
EBITDA	1,609	2,019	2,460	3,412	2,944	3,161
Funds from operations (FFO)	1,159	1,530	1,860	2,779	2,400	2,595
Interest expense	293	278	347	418	383	381
Cash interest paid	255	287	300	392	371	359
Operating cash flow (OCF)	797	1,510	2,399	2,722	2,358	2,872
Capital expenditure	1,691	1,635	1,837	1,653	1,943	2,432
Free operating cash flow (FOCF)	(894)	(125)	562	1,069	415	440

Ontario Power Generation Inc.--Financial Summary

Discretionary cash flow (DCF)	(909)	(426)	545	1,050	396	423
Cash and short-term investments	418	349	648	889	868	1,753
Gross available cash	418	349	648	889	868	1,753
Debt	10,583	11,437	13,175	15,814	13,582	10,000
Common equity	11,911	13,127	14,275	15,532	16,967	18,989
Adjusted ratios						
EBITDA margin (%)	31.3	36.9	40.9	47.1	42.8	43.0
Return on capital (%)	4.4	5.2	5.4	7.2	6.0	7.1
EBITDA interest coverage (x)	5.5	7.3	7.1	8.2	7.7	8.3
FFO cash interest coverage (x)	5.5	6.3	7.2	8.1	7.5	8.2
Debt/EBITDA (x)	6.6	5.7	5.4	4.6	4.6	3.2
FFO/debt (%)	11.0	13.4	14.1	17.6	17.7	25.9
OCF/debt (%)	7.5	13.2	18.2	17.2	17.4	28.7
FOCF/debt (%)	(8.4)	(1.1)	4.3	6.8	3.1	4.4
DCF/debt (%)	(8.6)	(3.7)	4.1	6.6	2.9	4.2

Reconciliation Of Ontario Power Generation Inc. Reported Amounts With S&P Global Adjusted Amounts (Mil. C$)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2022									
Company reported amounts	10,217	18,813	7,349	3,161	2,037	256	3,161	2,997	17	2,557
Cash taxes paid	-	-	-	-	-	-	(207)	-	-	-
Cash interest paid	-	-	-	-	-	-	(234)	-	-	-
Lease liabilities	62	-	-	-	-	-	-	-	-	-
Postretirement benefit obligations/ deferred compensation	1,474	-	-	-	-	-	-	-	-	-
Accessible cash and liquid investments	(1,753)	-	-	-	-	-	-	-	-	-
Capitalized interest	-	-	-	-	-	125	(125)	(125)	-	(125)
Nonoperating income (expense)	-	-	-	-	64	-	-	-	-	-

Reconciliation Of Ontario Power Generation Inc. Reported Amounts With S&P Global Adjusted Amounts (Mil. C$)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Noncontrolling/ minority interest	-	176	-	-	-	-	-	-	-	-
Total adjustments	(217)	176	-	-	64	125	(566)	(125)	-	(125)
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	10,000	18,989	7,349	3,161	2,101	381	2,595	2,872	17	2,432

Liquidity

We assess OPG's liquidity as adequate because we believe its liquidity sources are likely to cover uses by more than 1.1x over the next 12 months and its net sources will remain positive even if its consolidated EBITDA declines 10%. We believe the company's predictable regulatory framework provides it with cash flow stability even in times of economic stress, which supports our use of slightly lower thresholds to assess its liquidity.

In addition, we believe OPG can absorb high-impact, low-probability events. This reflects its $3.2 billion various credit facilities and our expectation that it can reduce its high capital spending during stressful periods. Furthermore, our assessment reflects the company's generally prudent risk management, solid relationships with its banking group, and satisfactory standing in the credit markets.

Overall, we anticipate OPG can withstand adverse market circumstances over the next 12 months while maintaining sufficient liquidity to meet its obligations. The company's next major long debt maturity is in 2024, when about $600 million comes due, which we expect it will proactively address well in advance of the due date.

Principal liquidity sources

- Cash and liquid investments of about C$1.59 billion;
- Average credit facility availability of C$3.2 billion; and
- Estimated cash FFO of about C$2.3 billion.

Principal liquidity uses

- Debt maturities of about C$533 million;
- Capital spending of C$3.7 billion; and
- Distributions to noncontrolling interest holders of about C$20 million.

Environmental, Social, And Governance

Environmental factors are a moderately negative consideration in our credit rating analysis of OPG because it has a consolidated exposure to nuclear and hydroelectric generation. The company's nuclear generation exposes it to waste and storage challenges while its hydroelectric generation exposes it to water resource use.

Social factors are a moderately negative consideration in our credit rating analysis based on the health and safety risks related to its nuclear generation. However, OPG undertakes several initiatives, including nuclear byproduct and waste management, that comply with the Canadian Nuclear Safety Commission's (CNSC) rigorous regulatory requirements and employs a

comprehensive nuclear safety and emergency preparedness program designed to protect employees and the public, the environment, property, and assets, all while ensuring operational continuity. In addition, to manage the water resources, OPG uses hydrological models, weather forecasts, satellite imagery, weather station data, and other tools to manage water levels, flows, and water storage. These initiatives somewhat offset the environmental and social risks.

Group Influence

Our ratings on OPG incorporate a high likelihood that its provincial owner, the Government of Ontario, will provide extraordinary support to the utility during periods of financial distress. OPG plays an important role for Ontario because it supplies about half of the province's electricity. In addition, the utility plays a vital role in Ontario's energy and environmental policies. Furthermore, the province has a record of providing support, both directly and indirectly, to the utility. For these reasons, we view the likelihood of extraordinary government support as high.

Issue Ratings--Subordination Risk Analysis

Capital structure

OPG's capital structure comprises roughly C$10.1 billion of debt.

Analytical conclusions

We rate the company's senior unsecured debt at the same level as our issuer credit rating because its priority debt is less than 50% of its total consolidated debt. We also rate OPG's commercial paper at 'A-1(Low)' on the Canadian National Scale.

Rating Component Scores

Foreign currency issuer credit rating	BBB+/Stable/--
Local currency issuer credit rating	BBB+/Stable/--
Business risk	Strong
Country risk	Very Low
Industry risk	Low
Competitive position	Strong
Financial risk	Significant
Cash flow/leverage	Significant
Anchor	bbb
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Negative (-1 notch)
Liquidity	Adequate (no impact)
Management and governance	Satisfactory (no impact)
Comparable rating analysis	Negative (-1 notch)
Stand-alone credit profile	bb+

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria | Corporates | Industrials: Key Credit Factors For The Unregulated Power And Gas Industry, March 28, 2014
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- ARCHIVE | General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Ratings Detail (as of August 08, 2023)*

Ontario Power Generation Inc.

Issuer Credit Rating	BBB+/Stable/--
Commercial Paper	
Canada National Scale Commercial Paper	A-1(LOW)
Senior Unsecured	BBB+

Issuer Credit Ratings History

17-Jul-2020	BBB+/Stable/--
30-Jul-2019	BBB+/Negative/--
07-Jul-2015	BBB+/Stable/--

Related Entities

Hydro One Inc.

Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2

Ratings Detail (as of August 08, 2023)*

Canada National Scale Commercial Paper	A-1(LOW)
Senior Unsecured	A-
Hydro One Ltd.	
Issuer Credit Rating	A-/Stable/--
Senior Unsecured	BBB+
Ontario (Province of)	
Issuer Credit Rating	A+/Positive/A-1
Commercial Paper	
Foreign Currency	A-1
Senior Unsecured	A+
UMH Energy Partnership	
Senior Secured	BBB+/Stable

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings credit ratings on the global scale are comparable across countries. S&P Global Ratings credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

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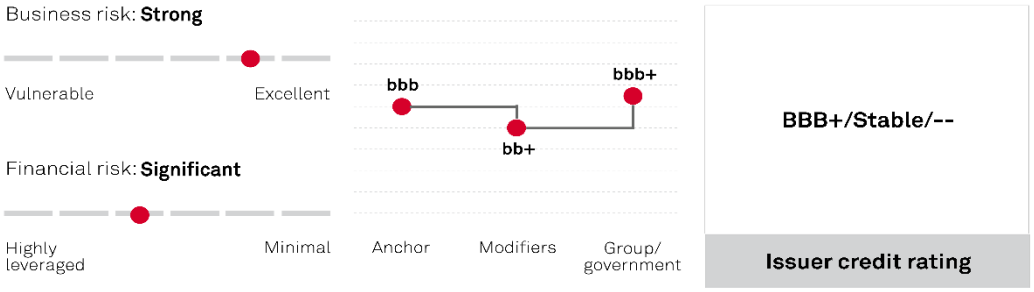
S&P Global
Ratings

RatingsDirect®

Ontario Power Generation Inc.

August 14, 2024

Ratings Score Snapshot



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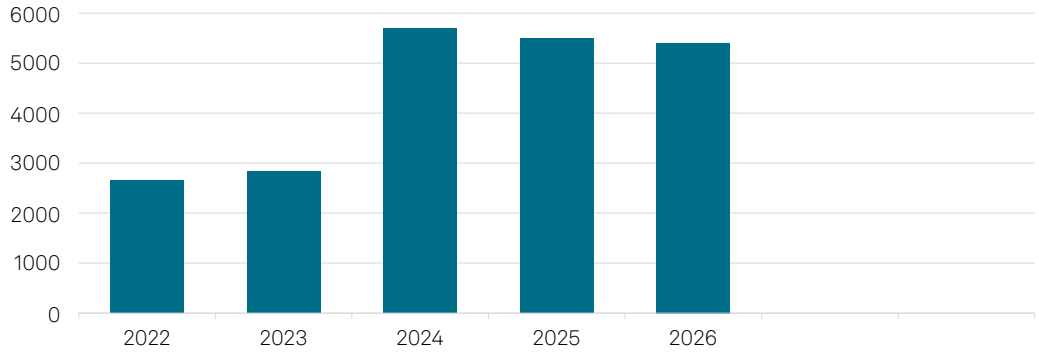
Credit Highlights

Overview

Key strengths	Key risks
Lower-risk, rate-regulated utility operations.	Limited geographic and regulatory diversity.
Diverse portfolio of power-generating assets.	Refurbishment of legacy nuclear generation plant exposes it to execution risk.
High likelihood of extraordinary government support.	Robust capital spending leads to negative discretionary cash flow, indicating a need for external funding.

Ontario Power Generation Inc. (OPG) is exposed to execution risks from several large capital investment projects. OPG's current forecasted capital investments budget is roughly 40% higher than the previous budget. The significantly higher capital investment plan primarily includes procuring long-lead components necessary for the refurbishment of Units 5-8 of the Pickering Nuclear Generating Station (GS), the ongoing Darlington Nuclear GS refurbishment, and other development projects. OPG has established a strong track record of executing Darlington GS refurbishment on time and on budget. However, the company's strategy of undertaking multiple large-scale projects in the coming years exposes OPG to potential execution risks.

Total capital expenditure

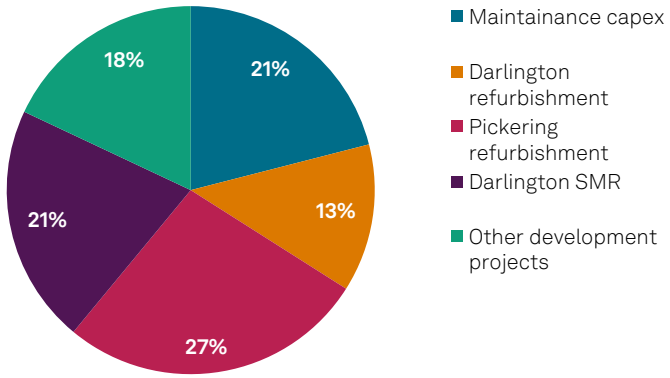


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Forecasted capex mix

2024-2026



Source: S&P Global Ratings.

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OPG's investment in developing first of a kind (FOAK) technology of small modular reactors (SMRs) is exposed to potential construction risk. Developing new nuclear power plants is a highly complex project characterized by extensive timelines, multi-billion-dollar investments, and inherent execution risks that can lead to significant cost overruns and delays. OPG partnered with GE Hitachi Nuclear Energy, AtkinsRealis, and Aecon to construct a 300-megawatt (MW) SMR project at the Darlington facility, with the potential to expand by constructing three additional SMRs at the same site. In our view, FOAK projects are highly susceptible to construction difficulties because the design is complex and could lead to cost overruns and delays.

The first SMR unit is expected to have a capacity of 300 MWs and the company plans to commission the unit by the end of 2029. In addition, OPG initiated the commencement of planning and licensing for three additional SMRs at the Darlington nuclear site, which is expected to start nuclear power plant construction phase only after the first unit is successfully commissioned. The Canadian Infrastructure Bank provided a $970 million commitment to fund

the project. Additionally, we expect the company to benefit from direct or indirect federal government incentives including clean electricity investment tax credit and clean technology investment tax credit to partially fund these investments.

As OPG scales up its investment in SMR projects, we believe the company's financial metrics could weaken if the company fails to execute the projects on time and on budget, does not fund its initial investments or cost overruns in credit supportive manner, or experiences regulatory lag in the recovery of its investments.

OPG's refurbishment of the Darlington Nuclear Plant remains on track for a timely completion. The company expects to refurbish all four units by the end of 2026. The company recently announced that it successfully refurbished Darlington Nuclear Generating Station Unit 3 169 days ahead of schedule and the Unit 1 and 4 continue to undergo refurbishments with an expectation that Unit 1 will return to service in Q4 2024, ahead of the schedule. Refurbishing the four Darlington units remains on plan for completion by the end of 2026. We expect OPG to assess and seek ways to manage the effects of the COVID-19 pandemic on the project's total cost, which is otherwise still in line with the $12.8 billion budget. Any material cost overruns would pressure OPG's credit measures. However, the expected early return of Unit 1 will modestly improve OPG's cash flow.

Furthermore, OPG plans to refurbish four units at the Pickering Nuclear Generating Station and other existing hydroelectric plants aimed at modernizing the infrastructure and improving generation capacity. Currently, the company remains focused on conducting pre-execution phase activities, which include preliminary engineering work and securing long-lead components for the Pickering refurbishment.

We expect OPG will continue to manage its regulatory risk and maintain financial measures in the lower half of our significant financial risk profile category. Specifically, we expect funds from operations (FFO) to debt of around 14.0%-16.0% through 2026 with modest financial cushion.

Outlook

The stable outlook on OPG incorporates the following expectations: more stable cash flows, no significant acquisitions, effective management of its regulatory risk, and that OPG will complete its future nuclear investments including refurbishments and small modular reactors on time and on budget. We also forecast FFO to debt of 14%-16%.

Downside scenario

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%. This could occur if the company experiences delays and cost overruns in its Darlington refurbishment program, faces adverse regulatory decisions, or undertakes significant debt-funded acquisitions. Alternatively, we could lower our rating if we downgrade the Province of Ontario or the relationship between OPG and the province unexpectedly deteriorates.

Upside scenario

Although highly unlikely, we could raise our ratings on OPG over the next 24 months if there is no change to its relationship with the Province of Ontario, it doesn't expand its nonutility

businesses through acquisitions, and it materially improves its financial measures, including FFO to debt consistently more than 20%.

Our Base-Case Scenario

Assumptions
• OPG continues to manage its regulatory risk; • Capital spending averages C$5.5 billion per year through 2026; • Distribution to noncontrolling interest holders average about C$20 million per year; • There are no material acquisitions; and • All debt maturities are refinanced or repaid.

Company Description

OPG is an Ontario-based electricity generation company. The company's generation fleet comprises about 18,225 MW of capacity. OPG is wholly owned by the Province of Ontario.

Business Risk

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

Our assessment of OPG's business risk profile also incorporates its contracted nonregulated generation, which accounts for about 30% of its consolidated EBITDA. The contracted, nonregulated power business increases the company's volumetric, operational, and commodity risks. However, these risks are partially offset by the business' long-term contracts with creditworthy counterparties. Given OPG's nonregulated power exposure, we assess it at the lower end of the range for its business risk profile category compared with its peers. In addition, the company is exposed to construction and execution risks related to its Darlington SMR project.

Financial Risk

We use our medial-volatility table financial benchmarks to assess OPG's financial risk, which reflects its lower-risk, regulated electric generation operations and effective management of regulatory risk. These benchmarks are more relaxed than the benchmarks we use for typical

corporate issuers. Under our base-case scenario, we assume capital spending averaging C$5.5 billion per year through 2026 and distributions to non-controlling interests of about C$20 million per year. We also expect OPG's discretionary cash flow will remain negative due to its elevated capital spending, indicating a need for external funding. In addition, we forecast FFO to debt around 14.0%-16.0% through 2026. Over the same period, we anticipate its S&P Global Ratings-adjusted FFO cash interest coverage will be about 6.0x, which further bolsters our financial risk profile assessment.

Debt maturities

- 2024: C$606 million;
- 2025: C$589 million;
- 2026: C$674 million;
- 2027: C$530 million; and
- Thereafter: C$7.7 billion.

Ontario Power Generation Inc.--Financial Summary

Period ending	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023
Reporting period	2018a	2019a	2020a	2021a	2022a	2023a
Display currency (mil.)	C$	C$	C$	C$	C$	C$
Revenues	5,474	6,022	7,240	6,877	7,349	7,434
EBITDA	2,019	2,460	3,412	2,944	3,161	3,155
Funds from operations (FFO)	1,530	1,860	2,779	2,400	2,595	2,319
Interest expense	278	347	418	383	381	388
Cash interest paid	287	300	392	371	359	395
Operating cash flow (OCF)	1,510	2,399	2,722	2,358	2,872	2,419
Capital expenditure	1,635	1,837	1,653	1,943	2,432	2,884
Free operating cash flow (FOCF)	(125)	562	1,069	415	440	(465)
Discretionary cash flow (DCF)	(426)	545	1,050	396	423	(484)
Cash and short-term investments	349	648	889	868	1,753	1,623
Gross available cash	349	648	889	868	1,753	1,623
Debt	11,437	13,175	15,814	13,582	10,000	11,684
Common equity	13,127	14,275	15,532	16,967	18,989	20,591
Adjusted ratios						
EBITDA margin (%)	36.9	40.9	47.1	42.8	43.0	42.4
Return on capital (%)	5.2	5.4	7.2	6.0	7.1	7.1
EBITDA interest coverage (x)	7.3	7.1	8.2	7.7	8.3	8.1
FFO cash interest coverage (x)	6.3	7.2	8.1	7.5	8.2	6.9
Debt/EBITDA (x)	5.7	5.4	4.6	4.6	3.2	3.7
FFO/debt (%)	13.4	14.1	17.6	17.7	25.9	19.8
OCF/debt (%)	13.2	18.2	17.2	17.4	28.7	20.7
FOCF/debt (%)	(1.1)	4.3	6.8	3.1	4.4	(4.0)
DCF/debt (%)	(3.7)	4.1	6.6	2.9	4.2	(4.1)

Reconciliation Of Ontario Power Generation Inc. Reported Amounts With S&P Global Adjusted Amounts (Mil. C$)

	Debt	Shareholder Equity	Revenue	EBITDA	Operating income	Interest expense	S&PGR adjusted EBITDA	Operating cash flow	Dividends	Capital expenditure
Financial year	Dec-31-2023									
Company reported amounts	10,542	20,409	7,434	3,155	2,084	269	3,155	2,538	19	3,003
Cash taxes paid	-	-	-	-	-	-	(441)	-	-	-
Cash interest paid	-	-	-	-	-	-	(276)	-	-	-
Lease liabilities	68	-	-	-	-	-	-	-	-	-
Postretirement benefit obligations/ deferred compensation	2,697	-	-	-	-	-	-	-	-	-
Accessible cash and liquid investments	(1,623)	-	-	-	-	-	-	-	-	-
Capitalized interest	-	-	-	-	-	119	(119)	(119)	-	(119)
Nonoperating income (expense)	-	-	-	-	101	-	-	-	-	-
Noncontrolling/ minority interest	-	182	-	-	-	-	-	-	-	-
Total adjustments	1,142	182	-	-	101	119	(836)	(119)	-	(119)
S&P Global Ratings adjusted	**Debt**	**Equity**	**Revenue**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from Operations**	**Operating cash flow**	**Dividends**	**Capital expenditure**
	11,684	20,591	7,434	3,155	2,185	388	2,319	2,419	19	2,884

Liquidity

We assess OPG's liquidity as adequate because we believe its liquidity sources are likely to cover uses by more than 1.1x over the next 12 months and its net sources will remain positive even if its consolidated EBITDA declines 10%. We believe the company's predictable regulatory framework provides it with cash flow stability even in times of economic stress, which supports our use of slightly lower thresholds to assess its liquidity.

In addition, we believe OPG can absorb high-impact, low-probability events. This reflects its $2.8 billion various credit facilities and our expectation that it can reduce its high capital spending during stressful periods. Furthermore, our assessment reflects the company’s generally prudent risk management, solid relationships with its banking group, and satisfactory standing in the credit markets.

Overall, we anticipate OPG can withstand adverse market circumstances over the next 12 months while maintaining sufficient liquidity to meet its obligations. The company’s next major long debt maturity is in 2025, when about $590 million comes due, which we expect it will proactively address well in advance of the due date.

Principal liquidity sources

- Cash and liquid investments of about C$1.08 billion;
- Average credit facility availability of C$2.8 billion; and
- Estimated cash FFO of about C$2.2 billion.

Principal liquidity uses

- Debt maturities of about C$418 million;
- Maintenance capital spending of C$5.1 billion; and
- Distributions to noncontrolling interest holders of about C$20 million.

Environmental, Social, And Governance

Environmental factors are a moderately negative consideration in our credit rating analysis of OPG because it has a consolidated exposure to nuclear and hydroelectric generation. The company's nuclear generation exposes it to waste and storage challenges while its hydroelectric generation exposes it to water resource use.

Social factors are a moderately negative consideration in our credit rating analysis based on the health and safety risks related to its nuclear generation. However, OPG undertakes several initiatives, including nuclear byproduct and waste management, that comply with the Canadian Nuclear Safety Commission’s (CNSC) rigorous regulatory requirements and employs a comprehensive nuclear safety and emergency preparedness program designed to protect employees and the public, the environment, property, and assets, all while ensuring operational continuity. Furthermore, OPG contributes to the Nuclear Segregated Funds, based on life cycle cost estimates and resulting funding liabilities for nuclear facilities decommissioning and its waste management. These costs are recovered in rates from customers. In addition, to manage the water resources, OPG uses hydrological models, weather forecasts, satellite imagery, weather station data, and other tools to manage water levels, flows, and water storage. These initiatives somewhat offset the environmental and social risks.

Government Influence

Our ratings on OPG incorporate a high likelihood that its provincial owner, the Government of Ontario, will provide extraordinary support to the utility during periods of financial distress. OPG plays an important role for Ontario because it supplies about half of the province's electricity. In addition, the utility plays a vital role in Ontario's energy and environmental policies. Furthermore, the province has a record of providing support, both directly and indirectly, to the utility. For these reasons, we view the likelihood of extraordinary government support as high.

Issue Ratings--Subordination Risk Analysis

Capital structure

OPG's capital structure comprises roughly C$10.5 billion of debt.

Analytical conclusions

We rate the company's senior unsecured debt at the same level as our issuer credit rating because its priority debt is less than 50% of its total consolidated debt. We also rate OPG's commercial paper at 'A-1(Low)' on the Canadian National Scale.

Rating Component Scores	
Foreign currency issuer credit rating	**BBB+/Stable/--**
Local currency issuer credit rating	**BBB+/Stable/--**
Business risk	**Strong**
Country risk	Very Low
Industry risk	Low
Competitive position	Strong
Financial risk	**Significant**
Cash flow/leverage	Significant
Anchor	**bbb**
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Negative (-1 notch)
Liquidity	Adequate (no impact)
Management and governance	Neutral (no impact)
Comparable rating analysis	Negative (-1 notch)
Stand-alone credit profile	**bb+**

Related Criteria

- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- ARCHIVE | Criteria | Corporates | Industrials: Key Credit Factors For The Unregulated Power And Gas Industry, March 28, 2014
- ARCHIVE | Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- ARCHIVE | Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- ARCHIVE | Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- ARCHIVE | General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009

Ratings Detail (as of August 14, 2024)*	
Ontario Power Generation Inc.	
Issuer Credit Rating	BBB+/Stable/--
Commercial Paper	
Canada National Scale Commercial Paper	A-1(LOW)
Senior Unsecured	BBB+
Issuer Credit Ratings History	
17-Jul-2020	BBB+/Stable/--
30-Jul-2019	BBB+/Negative/--
07-Jul-2015	BBB+/Stable/--
Related Entities	
Hydro One Inc.	
Issuer Credit Rating	A/Stable/A-1
Commercial Paper	
Local Currency	A-1
Canada National Scale Commercial Paper	A-1(MID)
Senior Unsecured	A
Hydro One Ltd.	
Issuer Credit Rating	A/Stable/--
Senior Unsecured	A-
Ontario (Province of)	
Issuer Credit Rating	A+/Positive/A-1
Commercial Paper	
Foreign Currency	A-1
Senior Unsecured	A+
UMH Energy Partnership	
Senior Secured	BBB+/Stable

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings credit ratings on the global scale are comparable across countries. S&P Global Ratings credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

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