AMPCO Interrogatory #001

Interrogatory

Reference:
Ref: A1-3-2

Question(s):

a) Please provide a copy of the 2025 Hydroelectric Facilities Performance Scorecard.

b) Please provide a copy of the 2025 Nuclear Facilities Performance Scorecard.

Response

a) and b)

The 2025 performance scorecards are not yet available. As noted in Ex. A1-3-2, p. 38, OPG files the hydroelectric scorecard and preliminary nuclear scorecard metrics by April 30 each year, with final nuclear scorecard metrics and benchmark quartile results by November 30 each year. Once they are available, the 2025 scorecards will be posted at https://www.opg.com/reporting/regulatory-reporting.

AMPCO Interrogatory #002

Interrogatory

Reference:
Ref: A1-4-1 Attachment #4

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Question(s):

a) Please provide a copy of OPG-PROC-0162.

b) Please provide a copy of the 24-16 Darlington Nuclear Refurbishment (DNR) Cost and Budget Management audit.

Response

a) See Attachment 1.

b) See Ex. L-D2-Staff-131 Attachment 15.

ONTARIO POWER GENERATION

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Document Number: OPG-PROC-0162		Revision: R005
Usage Classification: Information	Sheet Number: N/A	Page: 1 of 16

Ontario Power Generation

Procedure

TITLE
FLEET MANAGEMENT

AUTHORIZATION	
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DOCUMENT RELATIONSHIP	
Applicability:	OPG Wide
Receives Authority from:	OPG-PROG-0009, Items and Services Management

Document is Related to Pressure Boundary ☐	Document Requires CNSC Notification ☐

PURPOSE
This procedure identifies process requirements used to manage Ontario Power Generation Inc. (OPG), transport and existing plant equipment, and the administration of employer-provided vehicles.

DATES (YYYY-MM-DD)	
PDF Creation Date:	2023-04-26
Compliance Date:	Immediate

EXCEPTIONS
(a) Purchasing activities executed by Supply Chain (SC) for plant equipment are governed by OPG-PROC-0058, Procurement Activities.
(b) Equipment rentals that do not require proof of insurance should be completed at the local business unit level and require no involvement from Fleet Management Services (FMS).

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(c) This procedure does not apply to OPG Motor Pool CarShare Vehicles with the exception of Section 1.5 - Personal Use of Fleet Vehicles.

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1.0 DIRECTION

OPG Fleet governance is revised to align with industry standards and OPG's Fleet is defined to include assets that follow at least one of the following four principles:

(a) Require registration with Transport Canada (e.g., Vessels).

(b) Require registration and/or licensing with the Ministry of Transportation. This includes plated vehicles and non-plated vehicles (e.g., trailers, Rough Terrain Vehicles [RTV] and snowmobiles).

(c) Require proof of insurance (e.g., temporarily lease/rented assets, such as crane).

(d) Plant equipment that must be leased or rented.

1.1 Requesting a Fleet Asset

1.1.1 Vehicle/Trailer/Vessel/Leased Plant Equipment

To request a *Fleet Asset*, the Single Point of Contact (SPOC) *Requestor* from each Business Unit should perform the following activities:

(a) For *Standard Vehicle*s (*Pool Vehicle* or *Assigned Vehicle*), the online ordering tools from the Preferred Fleet Vendor (PFV) should be used. The *Requestor* should specify any requests for *upfitting*. Complete OPG-FORM-0185, Fleet Management Vehicle Request Package

(1) EV makes of vehicles (where feasible) are to be considered first. Passenger type EV, PHEV preferred, Sport Utility Vehicles (SUVs) PHEV preferred, Minivans (passenger type) PHEV preferred. Other types will be added as they become available.

(2) When requesting an Electric Vehicle (EV) or Plug in Hybrid Electric Vehicle (PHEV), the Requestor should contact Facilities Group to ensure that the facility can support the charging infrastructure for the added vehicle.

(3) For nuclear, Transport and Work Equipment (TWE) garage FLM to be contacted for specification review as the TWE Garage is responsible to maintain assets once received on site.

(b) FMS review requests and should perform the following activities:

(1) Ensure they are complete.

(2) Contact the Requestor for additional information or clarification on any additional requests such as upfitting.

(3) Identify either a new or redeployment vehicle which meets the requirements of Requestor.

(4) Electronically route the request to obtain Line of Business (LOB) approval for either a new unit or a redeployed unit in accordance with the approval matrix identified by the LOB.

(c) For all other *Fleet Assets* (i.e., *Non-Standard Vehicles*, Trailers, Vessels, Leased Plant equipment), the *Requestor* should perform the following:

(1) For *Non-Standard Vehicles* and/or vehicles requiring *Commercial Vehicle Operators Responsibility* (*CVOR*) registration, ensure the operator of vehicle has a valid operating licence (e.g., valid *CVOR* permit).

(2) Complete OPG-FORM-0185, Fleet Management Vehicle Request Package, and attach a separate sheet indicating the specifications along with any additional requirements (e.g., *upfitting*) and forward to FMS to review for completeness. Contact FMS to perform a Lease vs Buy Analysis for *Non-Standard vehicles*/equipment.

(3) When requesting an Electric Vehicle (EV) or Plug in Hybrid Electric Vehicle (PHEV) or Electric Plant Equipment, the *Requestor* should contact Facilities Group to ensure that the facility can support the charging infrastructure for the added vehicle.

(4) For nuclear:

(i) TWE garage FLM to be contacted for specification review as the TWE Garage is responsible to maintain assets once received on site.

(ii) Maintenance burden of new equipment must have sign off from Facilities management prior to new equipment ordered.

(5) If OPG-FORM-0185 with accompanying documentation is incomplete or incorrect, FMS returns to the *Requestor* for disposition.

(6) FMS may contact the *Requestor* (if required) for any clarification request or on any additional requests such as Up-fittings.

(7) Obtain LOB approval by forwarding completed forms and accompanying documentation to LOB Band ‘D’/’E’ Manager for approval.

(8) Upon obtaining LOB approval, forward OPG-FORM-0185 along with any Specification Sheet and associated documents and approvals to FMS for processing.

(d) Unless specified otherwise, a new *Fleet Card* is automatically requested with a new *Fleet Asset* request.

Note: FMS will advise if there are any exceptions (e.g., trailers etc.).

1.1.2 Additional Requirements for Assigned Vehicles

If the new vehicle request is for an *Assigned Vehicle*, OPG-FORM-0182, Application for Assigned Fleet Management Vehicles, should also be completed and approved by LOB, prior to online ordering (for *Standard Vehicle*) or sent in along with OPG-FORM-0185 (for *Non-Standard Vehicle*) to FMS.

1.1.3 Spare or Shop Fleet Card

(a) To request a Spare or Shop Fleet Card, complete OPG-FORM-0180, Application for Corporate Fleet Credit Card, and forward to your respective business unit SPOC.

(b) Business Unit SPOC should review and forward approved requests to FMS.

(c) Upon receipt of approved request, FMS should review to ensure completeness and processes the request.

1.1.4 Replacement Fleet Card

(a) Requests for a replacement *Fleet Card* should be made through the PFV.

(b) Requests for changing the dollar limits for any type of *Fleet Card* should be made through email to FMS.

(c) FMS should review and authorize PFV to either increase limits on existing card and/or issue a new *Fleet Card* as appropriate.

1.2 Processing Orders

During the order processing, should any changes to specifications arise which result in additional costs, revised costs should be approved in a similar manner as the original request, and sent to FMS for processing.

1.2.1 Order (Lease)

If FMS analysis determines that the *Fleet Asset* is to be leased, the following activities should be performed:

(a) For *Standard Vehicle* requests, once the final LOB approval has been obtained, the *Standard Vehicle* request is automatically sent to the PFV for processing. TWE at Nuclear sites should copied/informed.

(b) For *Non-Standard Vehicles*, FMS should forward the completed OPG-FORM-0185 with any specification sheet to PFV or TWE for nuclear sites for processing.

1.2.2 Order (Buy)

If FMS analysis determines that the *Fleet Asset* is to be purchased, the following activities should be performed:

(a) FMS returns the completed OPG-FORM-0185 and associated Specification Sheet (if applicable) to the *Requestor* and TWE at nuclear sites with an issued unit number.

(b) The *Requestor* creates a requisition for the *Fleet Asset* in accordance with OPG-PROC-0060, Requisitioning Items and Services, and routes for approval in accordance with OPG-STD-0017, Organizational Authority Register (OAR).

(c) Upon approval of the requisition, the *Fleet Asset* should be purchased in accordance with OPG-PROC-0058.

1.3 Delivery of Vehicles

1.3.1 After the order has been placed, FMS should send the *Requestor* or TWE at nuclear sites a *New Vehicle Package*.

(a) The *Requestor* ensures contents of the *New Vehicle Package* are complete and current.

(b) The *Requestor* should notify FMS if the package is incomplete or incorrect.

1.3.2 The *Assigned Vehicle* user or *Pool Vehicle* contact performs the following:

(a) Review, sign and return signed copy of OPG-FORM-0181, Employer-Provided Vehicle Agreement, and OPG-FORM-0183, Corporate Fleet Credit Card Agreement, to FMS.

(b) Comply with the requirements of OPG-STD-0092, Taxation of Employer Provided Vehicles, for *Assigned Vehicle*s.

1.3.3 For either a leased or purchased vehicle, the *Requestor* will be contacted by the dealer/up-fitter/supplier upon readiness for vehicle pick up or delivery.

(a) Upon delivery or pick-up, the *Requestor* should verify that the vehicle meets the requirements of their request.

(b) For nuclear, once the vehicle is delivered to site the TWE garage must perform PDI inspection before releasing the equipment to the *Requestor* for use.

(c) The *Requestor* or TWE at nuclear sites confirms the receipt of delivery and notes any deficiencies by email to FMS.

(d) All deficiencies should be addressed by the dealer/upfitter/vendor. FMS is to be informed of any outstanding or unresolved issues upon delivery and will facilitate resolution.

1.4 Maintenance Operation and Responsibility

The *Assigned Vehicle* user or *Pool Vehicle* user should comply with the following steps.

1.4.1 The *Assigned Vehicle* user or *Pool Vehicle* contact to ensure that vehicle keys to be held in secured locked location with controlled access at OPG facilities regardless of storage method.

1.4.2 The *Assigned Vehicle* user or *Pool Vehicle* user to enter each trip into the Log Book. OPG Fleet Log Books to be reviewed on a quarterly basis by the BU Manager(s).

1.4.3 The *Assigned Vehicle* user or *Pool Vehicle* contact should ensure vehicle maintenance is completed as per manufacturer’s schedule (based on time or mileage).

1.4.4 All vehicles must be fully inspected at least once a year by a licensed mechanic in a facility or shop that accepts OPG's PFV *Fleet Card* and Inspection report must be documented. OPG-FORM-186, Vehicle Inspection and Maintenance Report, can be utilized as a guide. Cost of this inspection should be charged to the assigned *Fleet Card* to the corresponding vehicle.

1.4.5 Each Operator of an OPG fleet vehicle should do a daily circle check prior to operating a vehicle.

(a) A record of the circle check and any damage or defects should be documented in the vehicles log book.

(b) If a circle check or vehicle operation reveals damage or defects, the Operator must notify their Supervisor and ensure corrective action/repairs are completed.

1.4.6 Wheel lug nuts occasionally loosen on vehicles after the wheels are removed and reinstalled. Whenever wheels are removed from a vehicle for service, the vehicle must be returned to the service centre to have the wheel lug nuts re-torqued based on the following criteria:

(a) *All on road plated Vehicle*s should be returned to the service centre after approximately 100km of driving to have the wheel lug nuts re-torqued.

(b) The Operator should record that the re-torque and, if applicable, further checks were completed in the vehicle log book.

(c) Wheel lug nuts should be installed using a calibrated torque wrench.

(d) Operator to ensure the proper type and grade of fuel is used at time of fuelling. (i.e., regular vs premium grades unless the vehicle requires premium fuel).

1.4.7 In case of a vehicle breakdown, the operator should contact PFV for assistance. PFV should inform the operator of the appropriate action to take.

1.4.8 In case of an accident, the Operator should follow the steps as outlined on OPG-FORM-0121, Automobile Accident Report and to include Ontario Reporting Centre Guidelines.

Note: Both PFV and FMS must be immediately informed of any accidents.

1.4.9 The *Assigned Vehicle* user or *Pool Vehicle* contact should ensure that any motor vehicle liability insurance card in the vehicle is up to date.

Note: Vehicle motor /vehicle liability insurance card is included in the *New Vehicle Package*, and new motor vehicle liability insurance card will be sent to *Assigned Vehicle* user or *Pool Vehicle* contact on an annual basis.

1.4.10 If the *Assigned Vehicle* User or *Pool Vehicle* contact needs a replacement motor vehicle liability insurance card (for either a lost or damaged card), FMS is to be contacted.

1.4.11 On a monthly basis, *Assigned Vehicle* users should submit completed and signed OPG-FORM-0124, Employer-Provided Automobile Report, and OPG-FORM-0113, Vehicle Time Log, to Taxation. Refer to OPG-STD-0092, for details.

Note: These requirements should be followed in order to comply with the Income Tax Act (Canada).

1.4.12 Odometer readings should be recorded or input on the PFV website by the *Assigned Vehicle* user or TWE at nuclear sites.

(a) *Pool Vehicle* contact should input odometer reading for all of their respective *Pool Vehicle*s.

(b) Delinquent odometer readings from vehicles are the accountability of the assigned business unit SPOC.

(c) If the *Assigned Vehicle* User or *Pool Vehicle* contact required replacement licence plates (for either lost or damaged plates), FMS to be contacted.

1.5 Personal Use of Fleet Vehicles

(a) OPG Fleet vehicles while intended primarily for OPG business use, may under certain circumstances, while travelling for OPG business be allowed for personal use. For example, enroute errands during the employee's commute (e.g., stopping at a convenience store or bank machine).

(b) Personal use of OPG Fleet vehicle during evenings and weekend travel is strictly prohibited unless conducting Company business after normal business hours. The privilege of personal use may be withdrawn at anytime by the company.

(c) Personal use of a Fleet vehicle is a reportable taxable benefit.

(d) If you are unsure of allowable uses or restrictions, contact your supervisor.

1.6 Utilization of Vehicles

FMS will periodically review the utilization of *Fleet Assets*. Units/assets with less than 8 logbook entries per month or 500km driven per month will be subject to a review between the Business Unit Leaders and FMS to determine the need for that vehicle/unit.

1.7 Licensing

1.7.1 Standard Vehicles

(a) For new vehicles (either leased or bought), the initial licensing should be done by PFV or the supplier.

(b) Annual renewals should be done by PFV, and renewal stickers, where applicable, will be sent to respective *Assigned Vehicle* users or TWE at nuclear sites and *Pool Vehicle* contacts annually.

1.7.2 Commercial Vehicles Operators Registration (CVOR)

(a) For *CVOR*, initial licensing should be done by PFV, TWE at nuclear sites, or other external vendor.

(b) The annual renewal process for the entire *CVOR* fleet, as stipulated by Ministry of Transportation – Ontario (MTO), should be completed by FMS and renewal certificate will be sent to respective *Pool Vehicle* contacts annually.

1.7.3 Trailers

(a) Initial licensing should be done by PFV, TWE at nuclear sites, or other vendor(s).

(b) The *Assigned Vehicle* user or *Pool Vehicle* contact should ensure routine inspections are performed.

Note: There are no annual license renewals for trailers.

1.7.4 Vessels

The initial registration and renewal process of the entire Vessel Fleet should be done by FMS and sent to Transport Canada.

1.8 Return Vehicle / Termination

1.8.1 When the vehicle is no longer required or needs to be retired, the *Requestor* should:

(a) Follow steps outlined in section of OPG-FORM-0184, Termination of Leased or Owned Assets.

(b) Return all contents of *New Vehicle Package* (such *Fleet Card*, motor vehicle liability insurance card) along with any licence plates, transponders to FMS or TWE at nuclear sites. FMS will determine if unit can be redeployed.

1.8.2 Vehicles must be clean, and any contents (personal or OPG) should be removed from vehicle.

1.9 Short Term Rentals

1.9.1 Vehicles

(a) Determine the appropriate method for short term rentals, by going to the FMS intranet site.

(b) OPG is participating with an OPG Motor Pool Carshare program. For short-term rentals, vehicles may be obtained through the OPG Motor Pool CarShare program. Refer to the FMS intranet site.

(c) If the OPG Motor Pool CarShare option is not appropriate for a given business travel need, continue to rent a car through OPG preferred vendors.

1.9.2 Plant Equipment

(a) Any short-term plant equipment rental requiring an insurance card will be coordinated through FMS. Requests should be sent to FMS (internal email: FLEETSERVICES).

(b) All other equipment rentals should be done at the local business unit level and require no involvement from FMS.

2.0 ROLES AND ACCOUNTABILITIES

2.1 Vice President, Supply Chain - Operations

2.1.1 Provides governance oversight for Fleet Management.

2.1.2 Ensures Staff adheres to process requirements.

2.2 Senior Manager, Supply Chain – Warehouse Operations

2.2.1 Provides overall program oversight.

2.2.2 Reviews issues that have been escalated by Supplier Contract Coordinator.

2.2.3 Ensures staff adheres to Governance.

2.3 Business Unit SPOC

2.3.1 Oversees their respective unit needs and requirements.

2.3.2 Processes new applications for a *Fleet Asset*.

2.3.3 Ensures monthly odometer readings are recorded in their respective business units.

2.4 Fleet Asset Users

2.4.1 Follows the requirements as per OPG-FORM-0181

2.4.2 Acts responsibly in accordance with OPG's Code of Business Conduct.

2.5 Supplier Contract Coordinator Fleet Services

2.5.1 Provides day-to-day support for Fleet Services acting as SPOC.

2.5.2 Ensures staff adheres to Governance.

2.5.3 Escalates issues which are not covered in the procedure.

2.5.4 Provides reports for all *Assigned Vehicle*s to assigned employees, Managers and Finance (Taxation) for taxable benefits.

2.5.5 Ensures Governance and all associated procedures, guide and forms are kept up to date, and revised as required.

3.0 DEFINITIONS AND ACRONYMS

3.1 Definitions

Assigned Vehicle is a vehicle which is assigned to single employee only.

***Commercial Vehicle Operators Responsibility* (*CVOR*)** refers to trucks with gross weight of over 4,500 kg.

Fleet Asset refers to Standard (Cars, Sport Utility Vehicles [SUV], Vans, Light Trucks) or *Non-Standard Vehicle* (Heavy Trucks, All Terrain Vehicles [ATV], RTV, Snowmobiles, Boats), and leased plant equipment.

Fleet Card is a card issued by PFV, for purchasing fuel and paying for maintenance for a given vehicle or for a group of vehicles.

New Vehicle Package is sent by FMS upon approval of *Fleet Asset* request, and includes a PFV *Fleet Card*, OPG-FORM-0181, OPG-FORM-0183, Log Book, motor vehicle liability insurance card slip, maintenance stickers, safety flash cards, etc.).

Non-Standard Vehicle refers to vehicles that are intended for off road uses.

Pool Vehicle is a vehicle assigned to a Fleet contact and intended for use by multiple employees.

Requestor is a single person who has been identified as a fleet contact for their business unit.

Spare/Shop Card is a *Fleet Card* for fuel/maintenance/shop supplies for a group of vehicles. These cards are for vehicles which do not have an assigned *Fleet Card* and/or for maintenance shops.

Standard Vehicle refers to a Car, Pickup Truck or an SUV.

Upfitting refers to aftermarket items, and usually not factory installed. (Examples: power tailgate, pintail ball, snow blade, back rack with amber beacon, winches etc.).

Vehicle refers to a transport vehicle (Car, Truck, Pickup, Boat, Trailer and Vessel).

3.2 Abbreviations and Acronyms

AIMS	Approved Information Management System
ATV	All Terrain Vehicle
CVOR	Commercial Vehicle Operators Responsibility
FMS	Fleet Management Services
LOB	Line of Business
OAR	Organizational Authority Register
OPG	Ontario Power Generation
PFV	Preferred Fleet Vendor (currently ARI Canada)
RTV	Rough Terrain Vehicle
SPOC	Single Point of Contact
SUV	Sport Utility Vehicle
TWE	Transport and Work Equipment

4.0 BASES, RECORDS AND REFERENCES

4.1 Bases

None

4.2 Records

The following records may be generated by use of this document and shall be registered in appropriate document management system in accordance with the following table.

Record Created	Associated Form or Template Number	QA Record? Y/N	Filing Information/Retention (AIMS Type/Sub-Type)
Automobile Accident Report	OPG-FORM-0121	N	Retained in accordance with OPG-PROC-0102, Risk Management and Insurance.
Application for Corporate Fleet Credit Card	OPG-FORM-0180	N	Retained by department until card is cancelled at which point record is filed in an Approved Information Management System (AIMS) RRC: LAW-0002 Retention: 6 years + current
Employer-Provided Vehicle Agreement	OPG-FORM-0181	N	Retained by department until vehicle is sold/surplused at which point record is filed in AIMS. RRC: LAW-0002 Retention: 6 years + current
Application for Assigned Fleet Management Vehicles	OPG-FORM-0182	N	Retained by department until vehicle is sold/surplused at which point record is filed in AIMS. RRC: LAW-0002 Retention: 6 years + current
Corporate Fleet Credit Card Agreement	OPG-FORM-0183	N	Retained by department until vehicle is sold/surplused at which point record is filed in AIMS. RRC: LAW-0002 Retention: 6 years + current
Termination of Leased or Owned Assets	OPG-FORM-0184	N	Retained by department until vehicle is sold/surplused at which point record is filed in AIMS. RRC: LAW-0002 Retention: 6 years + current
Fleet Management Vehicle Request Package	OPG-FORM-0185	N	Retained by department until vehicle is sold/surplused at which point record is filed in AIMS. RRC: LAW-0002 Retention: 6 years + current
Vehicle Inspection and Maintenance Report	OPG-FORM-0186	N	Retained by department until vehicle is sold/surplused at which point record is filed in AIMS. RRC: LAW-0002 Retention: 6 years + current.
Employer-Provided Automobile Report	OPG-FORM-0124	N	Retained by department RRC: LAW-0002

			Retention: 6 years + current
Vehicle Time Log	OPG-FORM-0113	N	Retained by department RRC: LAW-0002 Retention: 6 years + current
Email and correspondence (as applicable)	NA	N	Retained by department RRC: LAW-0002 Retention: 6 years + current

4.3 References

4.3.1 Performance References

OPG-FORM-0113, Vehicle Time Log

OPG-FORM-0121, Automobile Accident Report

OPG-FORM-0124, Employer-Provided Automobile Report

OPG-FORM-0180, Application for Corporate Fleet Credit Card

OPG-FORM-0181, Employer-Provided Vehicle Agreement

OPG-FORM-0182, Application for Assigned Fleet Management Vehicles

OPG-FORM-0183, Corporate Fleet Credit Card Agreement

OPG-FORM-0184, Termination of Leased or Owned Assets

OPG-FORM-0185, Fleet Management Vehicle Request Package

OPG-FORM-0186, Vehicle Inspection and Maintenance Report

OPG-PROC-0058, Procurement Activities

OPG-PROC-0060, Requisitioning Items and Services

OPG-STD-0017, Organizational Authority Register

OPG-STD-0092, Taxation of Employer Provided Vehicles

4.3.2 Developmental References

Canada Shipping Act 2001- Transport Canada (Canada)

Highway Traffic Act (Ontario)

Income Tax Act (Canada)

5.0 REVISION SUMMARY

This is an **intent** revision.

- General – Cover page authorities updated.
- General – Acronyms and abbreviations updated throughout as appropriate.
- General – Document references updated throughout as appropriate.
- General – Job and department titles updated throughout as appropriate. Dispositioned DCR# 162392
- Step 1.4.6 (a) – Revised for clarity.
- Step 1.4.6 (b) – Bullet stating vehicles to be taken to TWE garage after 100km has been removed and section renumbered accordingly.
- Step 1.7.1 (b) – Minor revisions for clarity

AMPCO Interrogatory #003

Interrogatory

Reference:

Question(s):

Please provide a list and summary of all Third-Party reviews, assessments or audits undertaken over the past 5 years related to material aspects of OPG's regulated business.

Response

This question is overly broad and therefore OPG declines to answer on the basis of relevance. OPG interprets the question as seeking information on all third-party reviews, assessments or audits undertaken over the past 5 years. OPG undertakes a wide range of third-party reviews and generates a large quantity of documents that may be captured by the question asked in this interrogatory that are not relevant to this Application. If the question was refined to reference specific materials relating to an issue on the approved Issues List, OPG could further consider the request and search for any such potentially relevant materials.

AMPCO Interrogatory #004

Interrogatory

Reference:
Ref: A1-4-2 p.2

Question(s):

Please add the following to Chart 1: a column to reflect 2025 Installed Capacity (MW); and a column to reflect 2025 actual generation (MW). In the response provide totals for the capacity and generation data columns.

Response

Refer to Chart 1 for the requested information. For clarity, the 2025 actual generation values are net of SBG spill.

Chart 1 – Regulated Hydroelectric Facilities General Information

Region	Generating Station	In-Service Year	Number of Units In-Service	Net In-Service Installed Capacity (MW)	2025 Installed Capacity (MW)	2025 Actual Generation (GWh)
Eastern	Abitibi Canyon	1933	5	344.8	344.8	1304.1
	Arnprior	1976	2	81.6	81.6	128.2
	Barrett Chute	1942	4	176.1	176.1	322.2
	Bingham Chute	1923	2	1.0	1.0	4.4
	Calabogie	2023[1]	2	10.7	10.7	35.1
	Chats Falls[2]	1931	4	96.0	96.0	519.5
	Chenaux	1950	8	143.7	143.7	719.0
	Chute[3]	1923	2	2.9	2.9	14.7
	Coniston	1905	2[4]	2.7	2.7	1.3
	Crystal Falls	1921	4	8.4	8.4	39.5
	Des Joachims	1950	8	428.8	428.8	2297.0
	Elliott Chute	1929	1	1.6	1.6	0.3
	Lower Notch	1971	2	274.2	274.2	344.1
	Matabitchuan	1910	4	9.6	9.6	19.7

Witness Panel: Hydroelectric Operations and Hydroelectric Projects, and Market Renewal Program

Region	Generating Station	In-Service Year	Number of Units In-Service	Net In-Service Installed Capacity (MW)	2025 Installed Capacity (MW)	2025 Actual Generation (GWh)
	McVittie	1912	2	2.8	2.8	14.6
	Mountain Chute	1967	2	170.2	170.2	315.9
	Nipissing	1909	0[5]	0	0	0
	Otter Rapids	1961	4	182.4	188.2	599.6
	Otto Holden	1952	8	242.8	242.8	1192.9
	R.H. Saunders	1958	16	1045.0	1045.0	6534.4
	Stewartville	1948	5	182.1	182.1	309.3
	Stinson	1925	2	5.4	5.4	20.7
Western	Aguasabon	1948	2	47.1	47.1	179.3
	Alexander	1930	5	68.9	68.9	368.9
	Auburn	1911	3	1.9	1.9	5.3
	Big Chute[6]	1993	1	10.0	10.0	25.2
	Big Eddy	1941	2	8.0	8.0	32.0
	Cameron Falls	1920	7	91.6	91.6	452.6
	Caribou Falls	1958	3	91.3	91.3	357.0
	Eugenia	1915	3	6.1	6.1	21.1
	Frankford	1913	4	2.6	2.6	6.8
	Hagues Reach	1925	3	3.6	3.6	11.5
	Hanna Chute	1926	1	1.4	1.4	3.1
	High Falls	1920	3	2.7	2.7	11.0
	Kakabeka Falls	1906	4	24.6	24.6	16.0
	Lakefield	1928	1	1.8	1.8	3.9
	Manitou Falls	1956	5	73.1	73.1	299.1
	Merrickville	1915	2	1.7	1.7	1.8
	Meyersburg	1924	3	5.2	5.2	9.7
	Pine Portage	1950	4	145.9	145.9	587.6
	Ragged Rapids	1938	2	8.3	8.3	32.1
	Ranney Falls	1922	3	19.5	19.5	52.8
	Seymour	1909	5	5.7	5.7	11.6
	Sidney	1911	4	4.4	4.4	9.0
	Sills Island	1900	2	1.8	1.8	5.3

Region	Generating Station	In-Service Year	Number of Units In-Service	Net In-Service Installed Capacity (MW)	2025 Installed Capacity (MW)	2025 Actual Generation (GWh)
	Silver Falls	1959	1	52.4	52.4	128.8
	South Falls	1907	3	5.9	5.9	19.3
	Trethewey Falls	1929	1	1.8	1.8	4.2
	Whitedog Falls	1958	3	67.8	67.8	256.1
Niagara	DeCew Falls 1	1898	4	22.8	22.8	85.2
	DeCew Falls 2	1943	2	144.0	144.0	1020.9
	Sir Adam Beck 1	1922	10	551.8[7]	551.8	2247.2
	Sir Adam Beck 2	1954	16	1,499.2	1,499.2	9986.7
	Sir Adam Beck PGS	1957	6	174.0	174.0	(49.2)[8]
TOTAL			**207**	**6559.7**	**6565.5**	**30938.4**

Notes:
1. Calabogie GS was originally placed in service in 1917 and was redeveloped in 2023.
2. Total station installed capacity is 192 MW; OPG is entitled to 50% of the capacity (96 MW) – refer to Ex. A1-4-2, Section 2.1.
3. Formerly Indian Chute GS.
4. Coniston GS is currently in redevelopment and will have two units in service following project completion.
5. Nipissing GS has no units currently in service.
6. Big Chute GS was originally placed in service in 1909, then subsequently redeveloped and placed in service in 1993.
7. MCR for Sir Adam Beck 1 GS was updated based on performance test on April 15, 2026.
8. Actual generation for the Sir Adam Beck PGS is negative because the energy withdrawn from the grid to operate the station in pump mode to fill the reservoir is always greater than the energy the station can generate using the water pumped into the reservoir. The PGS supports the safe and efficient operation of the Sir Adam Beck complex while its time-shifting of water provides consumer benefit.

CCC Interrogatory #002

Interrogatory

Reference:
Exhibit A1, Tab 3, Schedule 1, p. 4

Preamble:

OPG notes that, during the IR term, it intends 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.

Question(s):

Please provide a detailed list of potential new hydroelectric and nuclear generation options that OPG is currently evaluating. As part of the response, please provide any preliminary cost estimates, expected generation capacity, and a discussion of the status of OPG's work on these potential projects.

Response

OPG declines to provide the requested information on the basis of relevance. This interrogatory seeks information on potential future new hydroelectric and nuclear generation options. Such potential new options are not relevant to this Application and would not assist in deciding any issue on the approved Issues List in this Application.

CCC Interrogatory #003

Interrogatory

Reference:
Exhibit A1, Tab 3, Schedule 2, pp. 3, 18-22

Question(s):

a) Please explain why OPG prefers a price-cap approach for setting hydroelectric payment amounts relative to a revenue-cap type approach. As part of the response, please discuss whether OPG expects there to be annual variances in hydroelectric production during the 2027-2031 test period.

b) Given the methodology proposed for deriving the C-factor (i.e., cost of service derived capital (minus stretch) relative to capital amounts recovered through I-X (with inflation based on a 2025 estimate)), please explain why it is appropriate to establish the C-factor at fixed percentages on a final basis in the current proceeding. As part of the response, please explain the implications of the proposal on capital funding in the context of: (i) an inflation factor that is higher than estimated (3.49%); and (ii) an inflation factor that is lower than estimated.

c) Please confirm that OPG is seeking approval to establish GRCF percentages on a final basis in the current proceeding. Please advise whether there will be similar implications for rate funding of GRC expenses if inflation is higher or lower than estimated (3.49%) as provide in response to part (b) related to capital funding.

Response

a) OPG's proposed methodology for setting regulated hydroelectric payment amounts is a continuation of the price-cap index framework used to set such payment amounts during the 2017-2021 period, with the addition of a C-factor and GRCF. OPG believes there is some regulatory efficiency to adopting an iteration of the methodology previously used by OPG rather than introducing a new rate-setting framework, such as a revenue-cap approach.

OPG is not proposing a regulated hydroelectric production forecast for the 2028-2031 period as part of this proceeding. As discussed at Ex. A1-3-2, p. 8, the 2027 regulated hydroelectric payment amount is proposed to be determined by dividing the proposed 2027 revenue requirement (net of a stretch factor adjustment) by the proposed 2027 regulated hydroelectric production forecast. As the 2028-2031 regulated hydroelectric payment amounts would be determined mechanistically

under the proposed rate-setting framework, production forecasts beyond 2027 are not required. Some of the variability in the regulated hydroelectric production over the IR term would be addressed by the existing Hydroelectric Water Conditions Variance Account.

b) Establishing the C-factor at a fixed percentage provides predictable funding and administrative simplicity over the IR term. An alternative approach could be to update the calculation of the C-factor on an annual basis, based on the forecast capital-related revenue requirement, using the OEB inflation factor for the year in question.

The nature of the calculations used to determine the C-factor, as outlined in Ex. A1-3-2, Charts 6-8, is such that a higher inflation factor requires a lower C-factor, and a lower inflation factor requires a higher C-factor, all else equal. This relationship is driven by the fact that the C-factor is designed to bridge the gap between the capital funding afforded through the (I-X) adjustment and the forecast capital-related revenue requirement. Thus, a higher inflation component in the (I-X) leads to increased capital funding afforded through the (I-X) adjustment, reducing the C-factor required to bridge the gap. Conversely, a lower inflation factor would result in a lower amount of capital funding afforded through the (I-X) adjustment and a higher C-factor required to bridge the gap between the (I-X) adjustment and the forecast capital-related revenue requirement.

c) Confirmed, as discussed below.

The implications to the GRCF from a higher or lower inflation factor are the reverse of what is discussed in part b) for the C-factor. A higher inflation factor requires a higher GRCF and a lower inflation factor requires a lower GRCF, all else equal. This relationship is driven by the fact that the GRCF is designed to remove the (I-X) escalation of GRC amounts embedded in payment amounts. Thus, a higher inflation component in the (I-X) requires a higher negative GRCF to remove the escalated GRC amounts that would otherwise be embedded in the payment amounts. Conversely, a lower inflation component in the (I-X) requires a lower negative GRCF to remove the escalated GRC amounts that would otherwise be embedded in the payment amounts.

As discussed in part b) for the C-factor, OPG's proposal with respect to the GRCF is based on predictability and simplicity in the rate-setting framework. An alternative approach could be to update the GRCF on an annual basis to reflect the OEB inflation factor for the year in question.

CCC Interrogatory #004

Interrogatory

Reference:
Exhibit A1, Tab 3, Schedule 2, pp. 22-24

Question(s):

a) Please explain why the GHCVA should not also apply to variances in CRRR in 2027.

b) Please advise whether the balance in the GHCVA is proposed to be calculated on a cumulative basis (i.e., the total 2028-2031 variance must be in a credit position in order for there to be a balance for disposition).

c) Please confirm that based on OPG's proposal, line 1 in Chart 10 (Forecast Capital-Related Revenue Requirement), would be the baseline to which any variances are measured (i.e., the baseline CRRR is static across the test period).

d) Please confirm that the CRVA will record 2027 variances between actual capital-related revenue requirement for CRVA-eligible projects and the amounts recovered through payment amounts for those same projects.

Response

a) The hydroelectric custom price-cap index proposal discussed in Ex. A1-3-2, Section 2.0 includes determining the 2027 hydroelectric payment amount using a forward test year cost of service approach. As discussed at Ex. A1-3-2, p. 4, the proposed asymmetrical Global Hydroelectric Capital Variance Account ("GHCVA") is intended 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 over the 2028-2031 period is less than the capital-related revenue requirement provided through the payment amounts inclusive of the C-factor". There is no C-factor applicable in 2027 under the proposed rate-setting framework and, thus, the GHCVA is not proposed to apply.

b) Confirmed.

c) Confirmed. The Applicants propose to set the C-factor and underpinning CRRR amounts for the period as part of this Application.

d) OPG confirms that the Capacity Refurbishment Variance Account ("CRVA") will record 2027 variances between the actual capital related revenue requirement for CRVA-eligible projects and the capital-related revenue requirement amounts for those same projects underpinning the payment amounts. The amount actually "recovered through payment amounts" (as referred to in the question) would vary with production and, since the CRVA does not capture production variances, is not a fully accurate description.

CCC Interrogatory #005

Interrogatory

Reference:
Exhibit A1, Tab 3, Schedule 2, pp. 32, 34-35

Question(s):

a) With respect to the version of ScottMadden's benchmarking methodology that OPG proposes to use for determining the stretch factor, please confirm, or correct, that it is the version that includes: (i) technology type; (ii) unit age; (iii) refurbishment adjustment; and (iv) planned outages. As part of the response, please advise which chart in Exhibit F2, Tab 1, Schedule 1, Attachment 4 is the relevant chart.

b) Please provide a comparison of categories of nuclear costs to which the stretch factor is proposed to be applied in the current proceeding relative to the application of the stretch factor in the EB-2020-0290 proceeding. If any categories of costs have been removed from the application of the stretch relative to the approved categories in the EB-2020-0290 proceeding, please explain why the removal is appropriate.

c) Please provide a table that is comparable to Chart 17 showing the application of the stretch factor to the various categories of costs as approved in the EB-2020-0290 proceeding.

d) With respect to the proposed earnings sharing mechanism for the 2027-2031 period, please provide a list of all exclusions from regulated net income for earnings sharing purposes. For example, it appears that all DNNP-related costs and revenues are excluded from the determination of earnings for sharing purposes.

Response

a) OPG confirms that the version of ScottMadden's nuclear benchmarking methodology proposed for determining the stretch factor includes the following elements:
   - Adjustment for technology type
   - Adjustment for unit age
   - Adjustment for refurbishment (as applicable to Darlington)
   - Adjustment for outages through normalization of MWh

These adjustments are applied sequentially to develop normalized TGC/MWh values that better reflect differences in factors outside of management control.

The relevant chart is the final chart in Ex. F2-1-1, Attachment 4 that reflects all adjustments applied (i.e., econometric adjustments, refurbishment adjustment, and outage normalization). This chart presents the fully normalized TGC/MWh results and is the basis for the benchmarking comparison used in determining the proposed nuclear stretch factor in Ex. A1-3-2, Section 3.2.

b) Chart 1 below provides a comparison of cost categories included or excluded in the scope of OPG's proposed nuclear stretch factor calculations between EB-2020-0290 (proposed and approved) and this Application (proposed). No categories to which the stretch factor applied in EB-2020-0290 have been removed for this Application.

Chart 1
Cost Categories in OPG Nuclear Stretch Factor Scope

Category	Proposed EB-2020-0290	Approved EB-2020-0290	Proposed EB-2025-2097
Base OM&A	Include	Include	Include
Project OM&A	Include	Include	Include
Outage OM&A	Include	Include	Include
Pickering Cyclical Maintenance	N/A	N/A	Include
Allocated Corporate Support	Include	Include	Include
Asset Service Fees	Exclude	Include	Include
Nuclear Operations and Support Services Capital-related Revenue Requirement	Include	Include	Include
CRVA-eligible projects	Exclude	Include	Include
Darlington Refurbishment Program	Exclude	Exclude	Exclude
Pickering Refurbishment Program	N/A	N/A	Exclude

c) OPG understands this question to be applicable in the event there were categories of costs that have been removed from the scope of the proposed nuclear stretch factor in this Application relative to EB-2020-0290. As shown in part b), there are no such categories.

d) The Applicants in this proceeding, OPG and DNNP LP, are two distinct entities, each proposing their own revenue requirement, stretch factor and earnings sharing mechanism, among other aspects. As discussed in Ex. A1-3-2, Section 4.1, OPG is proposing to continue the earnings sharing mechanism approved in EB-2020-0290 with no adjustments to scope. DNNP LP is not proposing an earnings sharing mechanism, for the reasons further detailed in Ex. L-A1-SEC-015.

CCC Interrogatory #006

Interrogatory

Reference:
Exhibit A1, Tab 3, Schedule 2, Attachment 1, p. 16

Question(s):

Please provide the labour and non-labour weightings based on OPG's specific weighting of these factors instead of an industry average.

Response

This response was prepared by London Economics International LLC ("LEI")

LEI did not conduct such a calculation. And such a calculation for the inflation factor would not be appropriate. One of the most important criteria for evaluating the inflation factor (as noted on slide 10 of the inflation factor report) is that it should be exogenous to the utility. Use of industry weights ensures an exogenous inflation factor that is representative of industry conditions and will provide incentives to the regulated firm consistent with the theoretical underpinnings of incentive ratemaking and an index-based formula.

CCC Interrogatory #007

Interrogatory

Reference:
Exhibit A1, Tab 3, Schedule 2, Attachment 2, p. 32

Question(s):

Please further explain LEI's efforts to review regulatory filings for the noted potential Canadian peers. As part of the response, please explain why those companies' regulatory filings would not include the necessary information (specifically, hydro-specific OM&A expenses).

Response

LEI describes its efforts on pages 23 and 32-33 of the industry TFP report:

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

CCC Interrogatory #008

Interrogatory

Reference:
Exhibit A1, Tab 3, Schedule 2, Attachment 3, pp. 5-7

Question(s):

a) Please provide a list of the peers used in the TCB study.

b) Please provide a comparison of the peers used in the TCB study relative to the TFP study.

c) Please further explain the appropriateness of using four years of data in the study. As part of the response, please discuss whether LEI reviewed the results of the analysis including additional year(s) of data.

d) Please advise whether 2024 and 2025 data is now available. If so, please advise whether LEI has updated its model to reflect the most recent available data available.

e) To the extent that LEI performed the TCB analysis inclusive of all capital costs (as opposed to only sustaining capability investments), please provide the results of that analysis. If it did not perform that analysis, please explain why this sort of analysis is not reasonable in the context of expanding the study period from 4 years to a greater duration of time.

f) Please provide the categories of sustaining capability investments (and the total costs of those investments for each year during the study period) that were included in the OM&A + SC analysis for OPG. Please provide the percentage of the sustaining capital investments as a percentage of OPG's total hydroelectric capital investments for each year of the study period.

Response

This response was prepared by London Economics International LLC ("LEI")

a) LEI cannot accommodate this request because this data is subject to an NDA between EUCG and LEI.

b) LEI cannot accommodate this request because this data is subject to an NDA between EUCG and LEI, and creating a comparison may allow for release of identifiable data tied to a specific company in the EUCG dataset, violating the NDA.

c) As noted in response to IR L-A1-Staff-282 part (b)(i) above, LEI's reasoning for using a four-year study period is discussed on page 18 of the LEI benchmarking report:

> *"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."*

Furthermore, a materially longer study period would have reduced the number of peers and changed the makeup of the peer group that we would have been able to obtain from the EUCG dataset, while ensuring a consistent representation of power plants of varying sizes, vintages, and equipment. Therefore, LEI did not conduct analysis using additional years of data.

d) At the time that LEI was performing its work, 2024 and 2025 data was not available. LEI has not obtained updated data for those years from EUCG, and we understand that 2025 data is currently still not available. LEI has not sought to rerun the benchmarking analysis since the time of preparing our report.

e) LEI did not perform this analysis and does not consider this analysis to be appropriate given the purpose of the benchmarking study. As noted on pages 17-18 of the LEI benchmarking report:

> *"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 sustaining capability only, as reported by the EUCG database. This annual expenditure is included in the total annual expenditure for each company."*

Our reasoning for not expanding the study period beyond four years was discussed above in response to part (c) of this IR.

f) LEI cannot accommodate this request because this data is subject to an NDA between EUCG and LEI. However, according to EUCG's HPC Data Guide and Reporting Instructions, "sustaining capability" is defined as follows:[1]

> *Capital costs intended to replace/refurbish in-kind unit or plant generating capability*
>
> *These are capital costs encountered in maintaining existing assets in good running condition. They usually include replacements and may or may not include technological improvements that extend equipment useful life. However, I2 costs do not include costs related to increases in plant capability.*
>
> *Examples of I2 costs include:*
>
> - *Capital (major) turbine work*
> - *Capital (major) generator work*
> - *Licensing and re-licensing fees (not ongoing yearly costs)*

[1] EUCG. *HPC Data Guide and Reporting Instructions.* January 31, 2024. p. 56.

- *Runner replacement (it is acceptable to include 100% of costs associated with small/immaterial MW capacity increase)*

CCC Interrogatory #011

Interrogatory

Reference:
Exhibit A1, Tab 4, Schedule 4, Attachment 1, pp. 1-3

Question(s):

a) Please confirm, or correct, that the total cost for the four unit DNNP is expected to be approximately $21 billion (with $7.7 billion associated with Unit 1 and the common facilities).

b) Please provide a table showing both the costs and benefits of SMR technology relative to other traditional forms of nuclear generation.

c) Please provide the relevant reports, documents, and memos that explain the initial decision to move forward with the DNNP.

Response

a) As referenced in Ex. D2-4-8, Attachment 1, the Class 3 estimate to complete design, procurement, construction and commissioning of DNNP Unit 1, including site scope common to the four-unit program, is $7,698M. The current class 4 four-unit program estimate is $20,949M for the DNNP.

b) The DNNP forms part of the Province of Ontario's integrated energy plan ("IEP") which is the Government of Ontario's plan to ensure it can meet growing electricity needs for the period specified by the plan. As the OEB stated in EB-2020-0290:

> The OEB's role in this proceeding is distinct from the IESO and the OEB is not the system planner. As such, the OEB does not have the mandate or authority to consider or adjudicate on analyses and proposals respecting generating asset mixes for the Ontario electricity market in this proceeding.[1]

Therefore, it is not within the jurisdiction of the OEB to be the electricity system planner and consider alternatives to projects such as the DNNP forming part of the IEP. The OEB's jurisdiction is limited to considering the reasonableness and

[1] Procedural Order No. 2 and Decision on Motion, EB-2020-0290, April 29, 2021, p. 5.

prudence of the costs of the project in question for purposes of establishing rates. As such, the question posed is not relevant to these proceedings.

c) The applicants decline to provide the requested information on the basis of relevance, for the same reasons stated in part (b) above. In addition, this interrogatory seeks prior reports and documents developed for the project. These reports and documents have been superseded by the Release Quality Estimate provided at Ex. D2-4-8, Attachment 1 and they are not relevant to any issue in this proceeding.

CCC Interrogatory #013

Interrogatory

Reference:
Exhibit A2, Tab 3, Schedule 1

Question(s):

Please file any additional rating reports that were issued after the filing of OPG's application.

Response

Refer to Ex. L-A2-Staff-010, part b).

Environmental Defence Interrogatory #001

Interrogatory

Reference:
Exhibit A1, Tab 2, Schedule 2, Page 5

Question(s):

a) Please provide a table showing OPG's nuclear payment amounts for the past 10 years and forecast as far into the future as possible.

b) Please provide a table comparing OPG's nuclear payments amounts with the average cost of electricity in Ontario ($/MWh) over the past five years and forecast for the next five years.

c) Please explain the delta between the nuclear payment amounts and the average cost of electricity in Ontario. If the nuclear payment amounts are higher, please explain whether and why this.

d) If OPG were to adopt payment amounts for each nuclear generating station based on the costs attributable to each station, what would those be?

e) Of all the costs underlying the nuclear payment amounts, what percent is attributable to Pickering, Darlington, and other in each year over the rate term?

Response

a) Refer to Ex. L-A1-SEC-005.

b) and c)

The Application details the 2027-2031 proposed nuclear payment amounts in Ex. I1-3-1 and provides extensive evidence explaining and substantiating the underpinning costs and assumptions.

Past nuclear payment amounts were approved by the OEB in prior proceedings and are not subject to reconsideration in this proceeding. Therefore, OPG declines to provide this information on the basis of relevance.

Unlike OPG's payment amounts which are set by the OEB pursuant to its authority under section 78.1 of the *Ontario Energy Board Act, 1998* and the requirements set out in Ontario Regulation 53/05, the average cost of electricity is derived using different methodologies and regulatory objectives (i.e., it reflects a composite of multiple pricing mechanisms, including market outcomes, regulated rates, long-term supply contracts, and policy-driven instruments). As a result, the requested comparison is not probative and does not assist the OEB in determining appropriate payment amounts under said section 78.1.

d) The hypothetical analysis requested by this interrogatory reflects a significant departure from the established approach and methodology for setting nuclear payment amounts that has been evaluated and approved by the OEB in numerous past proceedings. Furthermore, it is not compliant with the approach of setting a blended payment amount for the OPG nuclear facilities and the DNNP facilities, as required by O. Reg. 53/05, section 14(2)7. As such, the Applicants decline to provide the requested analysis on the basis of relevance and lack of probative value.

e) Where applicable, cost information is provided separately for Darlington and Pickering throughout the Application (for example, Base OM&A costs are provided by facility in Ex. F2-2-1; Outage OM&A costs by facility in Ex. F2-4-1; Project OM&A costs are provided by facility in Ex. F2-3-1; Support Services costs are provided by facility in Ex. F3-1-1; rate base and depreciation information is provided by facility in Ex. B2 and Ex. F4-1-1). Using this and other available information, OPG derived, on a best efforts basis, the following approximate percentages of OPG's nuclear revenue requirements attributable to each of Darlington and Pickering (percentages do not sum to 100% due to certain unallocable elements):
   - 2027: 73% Darlington; 25% Pickering
   - 2028: 70% Darlington; 29% Pickering
   - 2029: 67% Darlington; 31% Pickering
   - 2030: 65% Darlington; 34% Pickering
   - 2031: 57% Darlington; 41% Pickering.

Environmental Defence Interrogatory #002

Interrogatory

Reference:
Exhibit A1, Tab 3, Schedule 2, Page 5

Question(s):

a) To help us better understand the proposed rate-setting frameworks, please prepare a table for each with columns for the following:

   i) Listing each factor that would be potentially relevant to cost recovery (e.g. production levels, demand, market prices, capital costs, O&M costs, unplanned outages, water levels, etc.);
   ii) Indicating for each factor whether the amount earned is based on a forecast set via this application, actuals, or otherwise; and
   iii) Indicating whether OPG or ratepayers bear the risk of actuals varying from forecasts, and an explanation as to why.

Response

a) During a multi-year incentive rate-setting period, there are a multitude of risk factors that may affect OPG's ability to recover its costs or that could otherwise affect its ability to earn the regulated rate of return. Preparing an exhaustive catalogue of these factors and assessing their impacts as requested by this interrogatory is impracticable within the timelines for responding to interrogatories. However, OPG notes that the key business and financial risks for its regulated assets were evaluated by Concentric Energy Advisors in their Common Equity Ratio Study. Please see Ex. C1-1-1, Attachment 1 for more information.

Environmental Defence Interrogatory #003

Interrogatory

Reference:
Exhibit A1, Tab 6, Schedule 1

Question(s):

a) Please provide a table listing each proposed capital investment of over $50 million. For each investment, please indicate whether need for the investment is within the scope of this proceeding. If not, please indicate why and include any relevant excerpts of O. Reg. 53/05 indicating the OEB must assume the investment is needed.

b) Please provide a table listing each proposed capital investment of over $50 million. For each investment, please indicate whether alternatives to the investment are within the scope of this proceeding. If not, please indicate why and include any relevant excerpts of O. Reg. 53/05 indicating the OEB cannot consider alternatives.

Response

a) and b)

The Applicants interpret "proposed capital investments of over $50 million" to be allocated capital projects with in-service amounts over $50 million in the 2027-2031 IR term. The requested information is summarized in Chart 1 below.

Chart 1 – Allocated Projects with Total In-Service >$50M in 2027-2031 IR Term

Business Unit	Project	Total In-Service in IR Term ($M)	Reference
OPG – Regulated Hydroelectric	Sir Adam Beck 1 GS Canal Isolation Preparedness Phase 1	65.0	Ex. D1-1-2, Table 1, Line 4
	Kakabeka Falls GS Redevelopment	487.1	Ex. D1-1-2, Table 1, Line 16
	Sir Adam Beck GS 2 G20/G19 Refurbishment	353.0	Ex. D1-1-2, Table 1, Line 17
	Matabitchuan GS Redevelopment	183.4	Ex. D1-1-2, Table 1, Line 18
	Otto Holden GS Refurbish Stop Log Piers	51.3	Ex. D1-1-2, Table 1, Line 25

	Aguasabon Dam Rehab – Hayes Lake Main Dam	70.0	Ex. D1-1-2, Table 1, Line 32
	Sir Adam Beck 1 GS G6/G8 Refurbishment	226.2	Ex. D1-1-2, Table 1, Line 34
	Sir Adam Beck 1 GS G4 Refurbishment	96.7	Ex. D1-1-2, Table 1, Line 35
	Sir Adam Beck 2 GS G17/G18 Refurbishment	344.5	Ex. D1-1-2, Table 1, Line 36
OPG – Nuclear	DN Digital Control, Common Process And Sequence Of Events Monitoring Computer Aging Management	77.1	Ex. D2-1-3, Table 1a, Line 11
	DN Unit 2 Turbine Control & Auxiliary Systems Upgrade	177.2	Ex. D2-1-3, Table 1a, Line 27
	DN Powerhouse Cranes Refurbishment	59.3	Ex. D2-1-3, Table 1c, Line 41
	Tritium Removal Facility Major Component Replacement Program	157.6	Ex. D2-1-3, Table 1c, Line 43
	DN Unit 2 and 3 Steam Generator Moisture Separator Replacement	135.3	Ex. D2-1-3, Table 1c, Line 49
	DN Turbine Rotors Replacement	1,692.7	Ex. D2-1-3, Table 1c, Line 51
	DN Unit 1 and 2 Generator Stator Rewind	312.3	Ex. D2-1-3, Table 1c, Line 53
OPG – Corporate	DNNP Enterprise Asset Management	56.0	Ex. D3-1-2, Table 1, Line 5
	Finance ERP Solution	114.6	Ex. D3-1-2, Table 1, Line 8
OPG – PRP	Common Services Building	57.4	Ex. D2-3-8, Table 3, Line 5
	Deep Water Intake	1,213.9	Ex. D2-3-8, Table 3, Line 7
	Pickering Refurbishment – Unit Refurbishment – Unit 5	8,474.1	Ex. D2-3-8, Table 3, Line 8
DNNP LP – DNNP	DNNP Unit 1 & Common Scope Facilities	6,584.9	Ex. D2-4-8, Table 3, Line 1

The investments in Chart 1 sustain and support the Applicants' regulated assets (including certain emergent equipment replacements or rehabilitations) and the construction of the Darlington New Nuclear Program, all of which are prescribed facilities under O. Reg. 53/05. This Application seeks OEB approval of the Applicants' proposed in-service capital for the prescribed facilities, to deliver safe and reliable electricity to the Province of Ontario.

As part of the OEB's authority to determine payment amounts for the Applicants' generation, it assesses the prudence of their proposals, which includes the need for and consideration of alternatives for that particular proposed investment in the prescribed facilities. However, the determination of payment amounts does not include generation planning and the economics related to generation planning in Ontario. This scope was expressly articulated by the OEB in EB-2020-0290 with respect to certain requested IESO and OPG cost-benefit analysis related to Pickering Nuclear Generation Station life extension, including underlying analysis:

> "The OEB's role in this proceeding is distinct from the IESO and the OEB is not the system planner. As such, the OEB does not have the mandate or authority to consider or adjudicate on analyses and proposals respecting generating asset mixes for the Ontario electricity market in this proceeding. A cost-benefit analysis of the Pickering Generating Station life extension, generation planning in Ontario, or the economics of generation planning, is out of scope for this payment amounts proceeding."[1]

The Applicants note that, as set out in its evidence, including at Ex. A1-3-1, the need for many of OPG's proposed investments during the 2027-2031 IR term, including the refurbishment of its Pickering Nuclear Generating Station, the construction of the Darlington New Nuclear Program and the refurbishment of its hydroelectric facilities, are expressly approved by the Province and/or form part of the Province's integrated energy plan.[2]

1. Procedural Order No. 2 and Decision on Motion, EB-2020-0290, April 29, 2021, p. 6.
[2] "Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7", Ministry of Energy and Mines

Energy Probe Interrogatory #002

Interrogatory

Reference:
A1-3-2

Preamble:

The Application proposes to continue setting hydroelectric payment amounts for 2027-2031 period using a price-cap index framework, as was used to set OPG's hydroelectric payment amounts during the 2017-2021 period, with the addition of a C-factor and GRCF.

This form of hydroelectric Custom IR is based on the Fourth Generation IR ("$GIRM") price cap index methodology in the RRF.

Question(s):

Does the proposed Custom IR have the same incentives for capital and OM&A incremental efficiencies as the 2017-2021 IR plan or does the addition of the C-factor reduce capital incentives? Please explain your answer.

Response

In the context of the substantial capital investment required in the 2027-2031 period, the proposed price-cap Custom IR framework for regulated hydroelectric facilities does not reduce efficiency incentives as compared to the 2017-2021 rate-setting framework. The annual (I-X) adjustment, with a stretch factor informed by total factor productivity and econometric cost benchmarking analyses conducted by London Economics International, preserves the efficiency incentives inherent in a typical price-cap framework for "steady state" operations.

The C-factor is designed to recover incremental revenue to address ongoing investments in the long-term availability and reliability of OPG's aging hydroelectric assets. The stretch factor reduction applied to the capital-related revenue requirement used in determining the C-factor provides an ongoing efficiency incentive for OPG's regulated hydroelectric capital costs. This stretch factor adjustment is presented in Ex. A1-3-2, Chart 6, lines 5 and 6.

Energy Probe Interrogatory #003

Interrogatory

Reference:
A1-3-2, Pages 3-4

Preamble:

"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 Ontario's Integrated Energy Plan."

Question(s):

a) Considering that OPG is owned by the Province of Ontario please explain what is meant by the phrase "could not be funded" in the quoted text.

b) Please explain why a typical price cap framework could not fund significant capital investments.

c) What was the total amount of hydroelectric capital investments that were funded under the existing price cap framework?

d) Did OPG experience any difficulties in the funding of hydroelectric capital investments under the existing price cap framework?

Response

a) The quoted text in the preamble is in reference to funding available through the price cap framework previously approved to set OPG's regulated hydroelectric payment amounts for the 2017-2021 period (i.e., a "typical price cap framework"). The identity of OPG's shareholder is not relevant to the determination of the rate-setting framework.

b) A typical price cap framework cannot fund capital investment when the capital-related revenue provided through annual (I-X) adjustments is less than the forecast capital-related revenue requirement over the period, such as that which supports

investment required to sustain and improve the reliability and safety of OPG's regulated hydroelectric assets.

In OPG's interpretation of a typical price cap framework, the regulated hydroelectric payment amount would be adjusted annually by multiplying the prior year payment amount by (I-X): where "I" is a generation industry inflation factor, and "X" is the sum of a productivity factor and stretch factor.

Refer to Ex. L-A1-Staff-271 for further discussion that compares the forecast capital-related revenue requirement against an (I-X) escalation of the proposed 2027 test year capital-related revenue requirement.

c) and d)
The OEB did not approve a regulated hydroelectric rate-setting framework for the 2022-2026 period as the payment amounts were legislatively frozen pursuant to O. Reg. 53/05, section 6(2)13.

Minogi Corp Interrogatory #001

Interrogatory

Reference:

- **Exhibit A1, Tab 4, Schedule 1**
- ***Buy Ontario Act (Public Sector Procurement), 2025*, S.O. 2025, c. 27, Sched. 1 ("*Buy Ontario Act*")**
- **Exhibit F3, Tab 1, Schedule 1**

Question(s):

a) Please confirm whether OPG has received any directives, guidance, policies or formal communications under the Buy Ontario Act relevant to the 2027-2031 period.

b) If yes to a), provide copies or summaries of such documents.

c) If no to a), describe anticipated directives/guidance for 2027-2031 and related assumptions in the application.

d) Please describe any plans, governance, or workstreams for *Buy Ontario Act* compliance during 2027-2031.

Response

a) OPG confirms that it has received new requirements under the Buy Ontario Act, 2025 through a Procurement Directive that was provided by the Ministry of Energy and Mines.

b) A summary of the Buy Ontario Procurement Directive and its implications to OPG is publicly available on the Government of Ontario web page at: Buy Ontario Procurement Directive | ontario.ca

c) Not applicable.

d) OPG will comply with the Buy Ontario Procurement Directive. This includes reviewing and updating internal procurement processes where applicable and monitoring for additional guidance and updates issued by the Province of Ontario.

SEC Interrogatory #005

Interrogatory

Reference:

Question(s):

Please provide a table that shows, for each year between 2008 and 2031, the actual or proposed, a) base nuclear payment amounts, b) nuclear DVA payment amounts riders, c) hydroelectric base payment amounts, d) hydroelectric DVA payment amounts riders.

Response

The requested information is provided in Attachment 1 to this response.

Numbers may not add due to rounding.

Filed: 2026-04-22
EB-2025-0297
Exhibit L-A1-SEC-005
Attachment 1
Table 1

Table 1
Historic, Current and Proposed Payment Amounts and Riders ($/MWh)

Line No.	Description	Note	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)
			Note 1	Note 1		Note 2	Note 2	Note 3	Note 4	Note 5		Note 6	Note 7	Note 8	Note 9	Note 10	Note 11	Note 12	Note 13	Note 14	Note 15		Note 16			
																						Proposed in EB-2025-0297				
1	**Hydroelectric Payment Amount**											41.67	42.05	42.51	43.15	43.88	43.88	43.88	43.88	43.88	43.88	51.39	54.97	59.20	62.02	64.21
2	**Previously Regulated Hydroelectric Payment Amount**		36.66	36.66	36.66	35.78	35.78	35.78	40.20	40.20	40.20															
3	**Newly Regulated Hydroelectric Payment Amount**								41.93	41.93	41.93															
4	**EB-2010-0008 Hydroelectric Payment Rider**					(1.65)	(1.65)																			
5	**EB-2012-0002 Hydroelectric Rider 2013-A**							3.04																		
6	**EB-2012-0002 Hydroelectric Rider 2014-A**								2.02																	
7	**EB-2013-0321 Previously Regulated Hydroelectric Rider 2015**									6.04																
8	**EB-2014-0370 Hydroelectric Rider 2015/16-A**									3.19	3.19															
9	**EB-2014-0370 Hydroelectric Rider 2015/16-B**																									
10	**EB-2016-0152 Hydroelectric Payment Rider A**												0.52	1.44	1.01											
11	**EB-2018-0243 Hydroelectric Payment Rider C**													1.16	1.25	2.05										
12	**EB-2020-0290 Hydroelectric Payment Rider**																1.03	1.03	1.03	0.69	0.69					
13	**EB-2023-0336 Hydroelectric Payment Rider**																		2.61	2.61	2.61					
14	**EB-2025-0297 Hydroelectric Payment Rider**																					(1.17)	(1.17)	(1.17)	-	-
15	**Nuclear Payment Amount**		52.98	52.98	52.98	51.52	51.52	51.52	59.29	59.29	59.29	77.96	78.64	77.00	85.00	89.70	104.06	107.79	103.48	102.85	111.33	206.70	192.42	202.74	199.16	219.60
16	**EB-2007-0905 Nuclear Payment Rider A**		2.00	2.00																						
17	**EB-2010-0008 Nuclear Rider**					4.33	4.33																			
18	**EB-2012-0002 Nuclear Rider 2013-A**							6.27																		
19	**EB-2012-0002 Nuclear Rider 2014-A**								4.18																	
20	**EB-2013-0321 Nuclear Rider 2015**									1.33																
21	**EB-2014-0370 Nuclear Rider 2015/16-A**									10.84	10.84															
22	**EB-2014-0370 Nuclear Rider 2015/16-B**																									
23	**EB-2016-0152 Nuclear Payment Rider A**												1.05	2.79	2.04											
24	**EB-2018-0243 Nuclear Payment Rider C**													2.20	2.28	6.13										
25	**EB-2020-0290 Nuclear Payment Rider**																1.16	1.25	1.15	5.34	7.58					
26	**EB-2023-0336 Nuclear Payment Rider**																		3.13	3.42	4.85					
27	**EB-2025-0297 Nuclear Payment Rider**																					7.19	5.04	5.36	2.48	2.19

Notes

1 2008 and 2009 payment amounts and riders effective April 1, 2008 per EB-2007-0905 Payment Amounts Order, p. 5.
2 2011 and 2012 payment amounts and riders effective March 1, 2011 per EB-2010-0008 Payment Amounts Order, pp. 4-5.
3 2012 payment riders effective March 1, 2013 per EB-2012-0002, p. 5.
4 Payment amounts effective November 1, 2014, per EB-2013-0321, pp. 6-7. Payment riders effective January 1, 2014 per EB-2012-0002 Payment Amounts Order, p. 5.
5 EB-2013-0321 payment riders effective January 1, 2015 per EB-2013-0321 Payment Amounts Order, pp. 7-8. EB-2014-0370 payment riders effective July 1, 2015 per EB-2014-0370 Payment Amounts Order, p. 3.
6 Payment amounts effective June 1, 2017 per EB-2016-0152 Payment Amounts Order, pp. 9-10.
7 Payment amounts effective January 1, 2018 and payment riders effective March 1, 2018 per EB-2016-0152 Payment Amounts Order, pp. 9-10.
8 Nuclear payment amount and EB-2016-0152 payment riders effective January 1, 2019 per EB-2016-0152 Payment Amounts Order, pp. 9-10. Hydroelectric payment amount effective January 1, 2019 per EB-2018-0243 Decision and Payment Amounts Order (December 13, 2018), p. 3. EB-2018-0243 payment riders effective January 1, 2019, per EB-2018-0243 Decision and Order (February 21, 2019), p. 5.
9 Nuclear payment amount and EB-2016-0152 payment riders effective January 1, 2020 per EB-2016-0152 Payment Amounts Order, pp. 9-10. Hydroelectric payment amount effective January 1, 2020 per EB-2019-0209 Decision and Payment Amounts Order, p. 5. EB-2018-0243 payment riders effective January 1, 2020, per EB-2018-0243 Decision and Order (February 21, 2019), p. 5.
10 Nuclear payment amount and EB-2016-0152 payment riders effective January 1, 2021 per EB-2016-0152 Payment Amounts Order, pp. 9-10. Hydroelectric payment amount effective January 1, 2021 per EB-2020-0210 Decision and Payment Amount Order, p. 4. EB-2018-0243 payment riders effective January 1, 2021, per EB-2018-0243 Decision and Order (February 21, 2019), p. 5.
11 Payment amounts and payment riders effective January 1, 2022 per EB-2020-0290 Payment Amounts Order, pp. 4-8.
12 Payment amounts and payment riders effective January 1, 2023 per EB-2020-0290 Payment Amounts Order, pp. 4-8.
13 Payment amounts and EB-2020-0290 payment riders effective January 1, 2024 per EB-2020-0290 Payment Amounts Order, pp. 4-8. EB-2023-0336 payment riders effective July 1, 2024 per EB-2023-0336 Decision and Order, p. 6.
14 Payment amounts and EB-2020-0290 payment riders effective January 1, 2025 per EB-2020-0290 Payment Amounts Order, pp. 4-8. EB-2023-0336 payment riders effective January 1, 2025 per EB-2023-0336 Decision and Order, p. 6.
15 Payment amounts and EB-2020-0290 payment riders effective January 1, 2026 per EB-2020-0290 Payment Amounts Order, pp. 4-8. EB-2023-0336 payment riders effective January 1, 2026 per EB-2023-0336 Decision and Order, p. 6.
16 Per Ex. I1-2-1, Table 1, Cols. (u) to (x) are illustrative only.

SEC Interrogatory #009

Interrogatory

Reference:
A1-3-1, p. 4

Question(s):

With respect to planning and preparation for potential new hydroelectric generation, how does OPG intend to handle any planning and preparation related costs incurred during the rate term?

Response

The regulated hydroelectric revenue requirement and associated rate-setting framework proposed in the Application do not include costs for planning and preparation for potential new hydroelectric generation facilities. The Application is not proposing any mechanism to recover any such planning and preparation costs incurred during the IR term.

To the extent the Ministry of Energy and Mines' proposal on "Advancing New Hydroelectric Generation in Ontario"[1] results in amendments to Ontario Regulation 53/05 under the *Ontario Energy Board Act*, *1998*, including to establish a variance account for recording pre-development expenses for OPG newly proposed hydroelectric projects, OPG would implement these requirements, including with respect to such an account.

[1] Environmental Registry of Ontario, "Advancing New Hydroelectric Generation in Ontario", ERO number 025-0449, April 29, 2025 <https://ero.ontario.ca/notice/025-0449>.

SEC Interrogatory #010

Interrogatory

Reference:
A1-3-2, p. 5-6

Question(s):

Please provide a table showing, for each year from 2027 to 2031, the difference between, a) the amount recovered (or eligible to be recovered) for hydroelectric as proposed in the current proposal, and b) the amount recovered (or eligible to be recovered) for hydroelectric under the ratemaking framework approved in EB-2016-0152. Please provide all calculations and assumptions used. Please also include, under the EB-2016-0152 framework scenario, any amounts that could be recovered through the Capacity Refurbishment Variance Account (CRVA).

Response

The requested information is provided in Chart 1, below. The analysis assumes that the revenue requirement and regulated hydroelectric payment amounts in 2027 are the same under both rate-setting frameworks and that, in the EB-2016-0152 framework scenario, the CRVA would continue to operate as currently.

As identified in Ex. A1-3-2, Chart 1, the differences between the two frameworks in the annual adjustment mechanism are due to the inclusion of a custom capital factor and a GRC factor, and different weightings between labour and non-labour components in the inflation factor. These differences result in the different hypothetical payment amounts (line 4) and indicative revenue recovery amounts (line 6) over the 2028-2031 period in the EB-2016-0152 framework scenario below, compared to the proposals set out in the Application.

The proposed treatment for recording amounts for the regulated hydroelectric facilities in the CRVA is described in Ex. H1-1-1, Section 5.6.1 and Ex. A1-3-2, Section 2.3.5. Namely, the Application proposes to record entries in the CRVA for the regulated hydroelectric capital costs relative to the forecast revenue requirement impact of eligible projects reflected in the capital-related revenue requirements (“CRRR”) underpinning the C-factor. A detailed derivation of the capital-related reference amounts for the CRVA is provided at Ex. H1-1-1, Attachment 5.

For purposes of estimating amounts that would be recorded in the CRVA under the EB-2016-0152 framework scenario, the response reflects the following:

- The 2027 hydroelectric CRVA reference amount is equal to $(6.8)M, per Ex. H1-1-1, Attachment 5; and
- The reference amount is escalated by I-X (3.34%, per Ex. I1-2-1, Table 1).

The result of the analysis is a hypothetical estimated addition to the CRVA of $773.5M over the IR term under the EB-2016-0152 rate-setting framework.

Chart 1 – Recoverable Amount Under Proposed and EB-2016-0152 Rate-setting Frameworks for Regulated Hydroelectric Facilities

		2027	2028	2029	2030	2031
	EB-2025-0297 Proposed Rate-setting Framework					
1	Proposed and Illustrative Hydroelectric Payment Amounts (Ex. I1-2-1, Table 1) ($/MWh)	51.39	54.97	59.20	62.02	64.21
2	Forecast Production (TWh)	32.5	32.5	32.5	32.5	32.5
3	**Indicative Revenue Recovery ($M)**	**1,668.3**	**1,784.4**	**1,921.8**	**2,013.3**	**2,084.4**
	EB-2016-0152 Rate-setting Framework					
4	Hypothetical Hydroelectric Payment Amounts Under EB-2016-0152 Method ($/MWh)	51.39	53.08	54.82	56.62	58.48
5	Forecast Production (TWh)	32.5	32.5	32.5	32.5	32.5
6	**Hypothetical Indicative Revenue Recovery ($M)**	**1,668.3**	**1,723.1**	**1,779.6**	**1,838.0**	**1,898.4**
	Capacity Refurbishment Variance Account Additions:					
7	Total Regulated Hydroelectric CRVA Eligible Projects' CRRR (Ex. H1-1-1, Attachment 5)	(6.8)	63.3	171.6	231.1	277.9
8	Less: Reference Amount	(6.8)	(7.1)	(7.3)	(7.5)	(7.8)
9	**Total Hypothetical Addition to Variance Account**	**0.0**	**70.3**	**178.9**	**238.6**	**285.7**
10	**EB-2016-0152 – Sum of Hypothetical Indicative Revenue Recovery and CRVA Additions** (line 6 + line 9)	**1,668.3**	**1,796.8**	**1,946.9**	**2,051.7**	**2,136.5**
11	Difference (line 3 - line 10)	-	(12.3)	(25.2)	(38.4)	(52.1)

As discussed in Ex. L-A1-Staff-289, while the CRVA captures the revenue requirement impacts of CRVA-eligible projects, it does not allow for the timely recovery of such funds. The proposed CRVA methodology in this proceeding (like the methodology approved in EB-2016-0152 and EB-2020-0290) requires the account balance to be evaluated on a cumulative basis over the IR term. This means that the balance cannot be evaluated until an application is filed after the conclusion of the term, with recovery beginning subsequent to such an application. This could result in significant delays between the incurrence of the impacts and the receipt of revenue. For example, for

CRVA amounts recorded over the 2027-2031 period, an application for disposition may not be filed until 2033, with collection beginning in 2034. The proposed rate-setting framework involving use of a C-factor is superior to the EB-2016-0152 framework in addressing such time gaps, particularly in a period when OPG is required to make substantial investment in the safety and reliability of its hydroelectric assets.

SEC Interrogatory #011

Interrogatory

Reference:
A1-3-2, p. 9

Question(s):

With respect to the proposed hydroelectric annual adjustment mechanism:

a) [A2-2-1, Attachment 1, p. 37] Please confirm that the forecast total regulated hydroelectric production between 2028 and 2031, before SBG losses, is forecast to be: 2028: 32.7 TWh, 2029: 33 TWh, 2030: 33 TWh, 2031: 32.9 TWh.

b) Please explain why OPG did not include as a component of the 2028-2031 hydroelectric payment amount adjustment formula a mechanism to prevent the C-factor from over-recovering capital costs as a result of the forecast increase in hydroelectric production before SBG (for example. see Decision and Order (EB-2014-0116), December 29, 2025, p.28-29).

c) Please provide OPG's view on the appropriate adjustment to the 2028-2031 hydroelectric payment amount adjustment formula to eliminate any double recovery of capital costs as a result of the increase in forecast hydroelectric production.

Response

a) OPG confirms that its 2025-2031 Business Plan contains the forecast total regulated hydroelectric production, before SBG losses, as set out in the question. OPG has not proposed or provided such a forecast in this Application as this information is not relevant under the proposed regulated hydroelectric rate-setting methodology (Ex. A1-3-2, Section 2.0). Outside of the C-factor, OPG's proposed hydroelectric rate-setting methodology is based on a detailed review of the 2027 test-year (Ex. A1-3-2, Section 2.2). Beyond the 2027 test year, regulated hydroelectric revenue will be determined formulaically by the proposed annual adjustment mechanism outlined in Ex. A1-3-2, Section 2.3.

b) OPG does not believe that a growth factor such as that approved in EB-2014-0116 is necessary because ratepayers are protected through the Hydroelectric Water Conditions Variance Account, which captures the net revenue impact of changes in regulated hydroelectric production due to variability in water conditions as described at Ex. H1-1-1, Section 5.1. In addition, as discussed in Ex. A1-3-2,

Section 2.3.5, OPG's proposal includes an asymmetric Global Hydroelectric Capital Variance Account 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 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 hydroelectric rate-setting framework also protects ratepayers through the stretch factor, which applies to the capital-related revenue requirement underpinning the C-factor, and through the continuation of the earnings sharing mechanism for OPG's nuclear and regulated hydroelectric facilities as described at Ex. A1-3-2, Section 4.1.

c) As noted in part a), OPG is not proposing a regulated hydroelectric forecast beyond 2027 as part of this Application. As noted in part b), OPG does not believe a growth factor such as that approved in EB-2014-0116 is necessary in the context of OPG's regulated hydroelectric rate-setting proposal in this Application.

SEC Interrogatory #012

Interrogatory

Reference:
A1-3-2, p. 18

Question(s):

Please provide a full table that shows the 2027 to 2031 hydroelectric total revenue requirement (including non-capital-related revenue requirements).

Response

Outside of the C-factor which relies on a five-year forecast of capital related revenue requirement, OPG's proposed hydroelectric rate-setting methodology is based on a cost of service review of the 2027 test-year (Ex. A1-3-2, Section 2.2). Beyond the 2027 test year, regulated hydroelectric revenue would be determined formulaically by the proposed annual adjustment mechanism outlined in Ex. A1-3-2, Section 2.3. Accordingly, OPG has not filed annual hydroelectric revenue requirement forecasts beyond 2027, and declines to provide this information as it is not relevant under the proposed hydroelectric rate-setting framework.

SEC Interrogatory #013

Interrogatory

Reference:
A1-3-2, p. 26

Question(s):

With respect to interaction between various accounts:

a) Please explain the interaction between the CRVA and the proposed tax-related accounts.

b) Please explain why the tax related impacts are not excluded from the Global Hydroelectric Capital Variance Account (GHCVA).

Response

a) Refer to Ex. L-H1-Staff-248.

b) The income tax related impacts are not excluded from the proposed GHCVA because they form part of the regulated hydroelectric capital-related revenue requirement for which the GHCVA is intended to record variances, as described in Ex. A1-3-2, pp. 22-26, as part of OPG's proposed regulated hydroelectric rate-setting framework that includes a C-factor. The mechanism described at Ex. A1-3-2, lines 9-26 is intended to address any potential overlap between the GHCVA and the income tax related deferral and variance accounts.

SEC Interrogatory #016

Interrogatory

Reference:
A1-3-2, Attachment 1

Question(s):

With respect to the LEI, *Analysis of Inflation Factor Options for OPG's Regulated Hydroelectric Business* Report.

a) [p.2, 6, 16] Please confirm that LEI is recommending application of an inflation factor to historical costs that are in fact not inflating (such as depreciation and cost of capital). Please describe in detail all investigations or other work done by LEI to determine the extent to which inflation in fact increases depreciation of capital assets and cost of capital over time.

b) [p.6] Please describe and explain the interaction between a) increases in the gross revenue from the hydroelectric business due to the annual IRM adjustments to payment amounts, b) changes in the gross revenue from the hydroelectric business due to changes in units of production, c) the Gross Revenue Charge, d) application of the I-factor to the GRC, e) changes to the level of the GRC as determined by the government from time to time, and f) total factor productivity of the hydroelectric business.

Response

Part a) of this response was prepared by London Economics International LLC ("LEI")

a) LEI is proposing application of the inflation (I) factor to the total revenue requirement that will be subject to the price cap.

b) OPG understands the question to be with respect to the interaction between the inflation factor and the six items described in sub-parts a-f.
   a. Hydroelectric gross revenue is the product of the hydroelectric payment amount and actual production. Per the proposed rate-setting framework, the hydroelectric payment amount is escalated by (I-X)+C-GRCF on an annual basis. Thus, all else equal, the inflation factor increases gross revenue.
   b. There is no direct interaction between the inflation factor and changes in actual production. As noted above, hydroelectric gross revenue is the product of the

hydroelectric payment amount and actual production. Thus, all else equal, increased production results in an increase in gross revenue.

c. As discussed at Ex. A1-3-2, pp. 20-21, 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.
d. Interaction between the inflation factor and GRC is discussed at Ex. L-A1-CCC-003, part c).
e. Impacts resulting from potential changes to the level of GRC as determined by the government are proposed to be captured in the Gross Revenue Charge Variance Account. See Ex. L-A1-Staff-270 for further information.
f. Not applicable. Neither OPG nor LEI calculates total factor productivity of OPG's regulated hydroelectric facilities.

SEC Interrogatory #017

Interrogatory

Reference:
A1-3-2, Attachment 1

Question(s):

With respect to the LEI, *Analysis of Inflation Factor Options for OPG's Regulated Hydroelectric Business* Report.

a) [p.11] Please describe the extent to which each of the cited precedents includes regulated hydroelectric assets. If the cited precedents include significantly less hydroelectric assets than OPG's regulated hydroelectric business, please discuss how that fact should be taken into account in assessing the relevance of each of the cited precedents.

b) [p.14] Please discuss the reasons for the volatility of capital cost indices.

c) [p.22] Please provide whatever information is available on the reasons why OPG's indicative labour cost growth has substantially exceeded AWE growth over the 22-year comparison period.

d) [p.29] Please explain why trends in the value of existing capital assets and the value of the services they provide would be relevant to the inflation impact on the cost of new capital assets.

Response

a) LEI understands the term "cited precedents" in the question to refer to the content on slides 11 and 13 of the inflation factor report. On slide 11, LEI listed recent decisions by regulators across Canada that applied several inflation factor evaluation criteria – including: (i) relevance to utility costs, (ii) exogeneity, (iii) source reliability, (iv) data availability, (v) precedence and simplicity, and (vi) index stability. On slide 13, LEI listed examples of the inflation indices recently approved by other regulators.

   None of the examples cited on these slides are directly related to the regulated hydroelectric business. However, these examples all relate to regulated utility businesses, and demonstrate the application of the aforementioned evaluation criteria by regulators as they consider appropriate measures of inflation. These

evaluation criteria are relevant regardless of the regulated utility business in question.

b) As noted on slide 26 of LEI's inflation factor report, capital-specific indices tend to be more volatile due to their sensitivity to economic cycles. In fact, the OEB has expressed concerns with volatility of the capital input measure and refrained from using it again for this reason:

> "The 3-factor IPI included capital, labour, and nonlabour indices. However, the Board and many stakeholders were concerned that the resulting numbers generated do not appear reasonable and result in unacceptable volatility. … The primary source of volatility in the 3-factor IPI is the capital sub-index."

c) Statistics Canada's AWE index (Ontario, industrial aggregate excluding unclassified businesses) is a broad index that includes data on labour costs from a range of industries:

- Forestry, logging and support
- Mining, quarrying, and oil and gas extraction
- Utilities
- Construction
- Manufacturing
- Trade
- Transportation and warehousing
- Information and cultural industries
- Finance and insurance
- Real estate and rental and leasing
- Professional, scientific and technical services
- Management of companies and enterprises
- Administrative and support, waste management and remediation services
- Educational services
- Health care and social assistance
- Arts, entertainment and recreation
- Accommodation and food services
- Other services (except public administration)
- Public administration

In contrast, OPG's workforce includes highly technical and specialized individuals, as well as unionized employees. LEI theorizes that these factors contribute to OPG's higher labour cost growth.

d) LEI is recommending an inflation factor that would be applicable to the total revenue requirement, not just the “cost of new capital assets” as implied in the question. As part of the consideration of capital-related inflation indices, slide 29 of LEI’s inflation factor report presents a theoretical model for capturing the inflationary pressures on capital assets known as the implicit rental price of capital, which reflects the cost of using capital over time and incorporates key economic variables such as depreciation, inflation, the cost of capital, and tax effects.

SEC Interrogatory #018

Interrogatory

Reference:
A1-3-2, Attachment 2

Question(s):

With respect to the LEI, *Empirical Analysis of Total Factor Productivity Trends in the North American Hydroelectric Generation Industry* Report:

a) [p.7] Please confirm that the effect of rising asset maintenance costs and fixed production capabilities is largely or completely offset by the declining nominal and real costs of capital assets of the hydroelectric business over time in determining the actual total cost of production, but not in determining the TFP.

b) [p.9] Please confirm that, in addition to the factors cited, regulatory rules, controls or limitations on hydroelectric production can affect outputs as they are modified over time. To what extent, if any, has LEI considered past and/or prospective changes in hydroelectric production parameters (e.g. changes to flow restrictions, dispatch limitations, spill requirements, etc.) in adjusting the data or results on hydroelectric outputs?

c) [p.9] Please describe the "increasingly stringent regulatory requirements" referred to.

Response

This response was prepared by London Economics International LLC ("LEI")

a) The question makes assertions that are inconsistent with what LEI observes in its industry TFP study.

   More specifically, as observed in the workpapers and results of LEI's TFP study for the hydroelectric industry, operation and maintenance costs for the industry are rising in nominal and real dollar terms over the study timeframe. LEI also observes that the capital stock (as proxy measured by MCR value) for the industry is relatively stable over the study timeframe for the industry as a whole, although some plants experience reductions while others experience improvements in certain years. In addition, when looking at the monetary method, LEI can confirm the capital stock

is rising in nominal dollar terms for the industry, and the real capital stock for the industry is also rising (not declining, as suggested in the question).

The costs of production is a common term used in the electric industry. When used to evaluate efficiency of markets, it commonly refers to marginal costs of producing energy, and therefore captures fuel cost and variable O&M. Some practitioners may also include fixed O&M expenses and capital-related charges when discussing total production costs. It is unclear to LEI how the SEC is defining production costs in the question. Hydroelectric generation does not have physical fuel costs like fossil fuel fired power plants. The O&M, which is part of this TFP study, is rising as discussed above. The capital-related metrics and costs, as discussed above, are also rising.

b) Changes to flow restrictions and dispatch limitations are captured in the TFP output measure of annual generation measured in MWh. Hydroelectric spill (curtailed generation) is not captured in this output measure. Hydroelectric generation curtailment is a rare occurrence in most US regions. Moreover, LEI understands that hydroelectric spill has become a less frequent occurrence in Ontario and is minimal when compared to total generation.

c) This quotation was in the context of discussing how a negative TFP trend is consistent with expectations given conditions faced in the hydroelectric generation industry. More specifically, we were referring to increasingly stringent regulatory requirements for safety and environmental purposes, such as requirements related to fish passage, recreation and public access, sediment control, endangered species and biodiversity protection, water quality, etc. These requirements place greater pressure on OM&A costs, capital expenditures, or both.

Ex. F1-1-1, Section 3.2.3.2 describes various regulatory commitments that affect OPG's hydroelectric facilities, including dam and public safety obligations; environmental obligations with Fisheries and Oceans Canada, the Ministry of Environment, Conservation and Parks, and the Ministry of Natural Resources; IESO requirements; and contractual obligations with partners through joint works agreements (such as New York Power Authority).

SEC Interrogatory #019

Interrogatory

Reference:
A1-3-2, Attachment 2

Question(s):

With respect to the LEI, *Empirical Analysis of Total Factor Productivity Trends in the North American Hydroelectric Generation Industry* Report:

a) [p.24] Please describe what analysis LEI did to ensure that there are no TFP trends in the data based on total MW of the generator. Please provide the TFP results if all generators with under 1,000 MW of capacity are excluded.

b) [p.25] Please explain why payments for things like SBG, HIM, ancillary services, or other revenues that represent increases in the outputs of the hydroelectric business, are excluded.

c) [p.27] Please explain what conclusions, if any, should be drawn from the fact that OPG is significantly larger than all of the peers, and its fleet is older than most of the peers. What adjustments, if any, have to be made to the peer group TFP to reflect size and age in applying the results to OPG?

d) [p.29] Please add OPG to Figure 9.

e) [p.29] What investigations, if any, did LEI carry out to determine that administration costs would not impact the TFP trend of OPG?

f) [p.35] Please confirm that the O&M input was deflated using the same inflation factor that LEI is proposing for the I-factor. If not confirmed, please explain why and assess the impact of the difference.

g) [p. 37] Please provide separate versions of Figure 14 for each of the US and Canada (OPG).

Response

This response was prepared by London Economics International LLC ("LEI")

a) LEI does not understand the first part of the question. As for the second part of the question, our TFP study methodology was intentionally designed to include as broad a peer group as possible, which is why, as noted on page 11 of the TFP report:

> "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. 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)."

The request to rerun the analysis and provide TFP results for a subset of peers is not appropriate and would not constitute an industry TFP study, and thus would not be fit for purposes of calibrating the base productivity component of the X factor. Further, this request would take a non-trivial amount of time and effort to complete.

b) Revenues from sale of ancillary services, payments related to Surplus Baseload Generation ("SBG") or the Hydroelectric Incentive Mechanism ("HIM"), or water management for flood control and recreational use, are difficult to represent in an industry TFP study because the data is not readily available on a consistent basis across peers. These additional payments for services tend to also be (a) correlated with capability and/or energy sales, and (b) much smaller volume than energy sales. Therefore these additional services and revenues were not explicitly included in LEI's TFP study.

c) As indicated in Figure 6 of the TFP report, which is reproduced below, OPG is the second largest peer in terms of installed capacity of its entire fleet. There is one generation owner that has an even larger fleet. However, OPG operates individual hydroelectric plants ranging in size, similar to the size of the facilities owned by other peers. Furthermore, as noted in response to IR L-A1-Staff-279 part (h), OPG's

regulated fleet accounts for only 15% of the industry capacity considered in the TFP study (based on data as of 2023).

In terms of average asset age, several peers have older fleets than OPG, including Alabama Power, Southern California Edison Company, PacifiCorp, Avista Corporation, Union Electric, Duke Energy Progress, Lockhart Power Company, and Chelan County Public Utility District, as seen in Figure 6 of the TFP report, which is reproduced below. LEI did not adjust the list of peers or the data and does not believe that any adjustment is warranted.

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.

In summary, OPG is just one entity as part of a much larger industry sample. Nonetheless, LEI notes that removing OPG from the industry sample does not significantly impact the TFP results. As stated on page 6 of the TFP report:

> *"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."*

d) Please refer to the 'TFP_dataset' tab in the TFP working paper for the physical model filed in Ex. L-A1-Staff-002, where the requested information can be obtained.

e) As noted on page 29 of the TFP report:

> *"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."*

f) Yes, OPG's O&M costs were deflated using AWE (Ontario, industrial aggregate) for the labour component and GDP-IPI FDD (Canada) for the non-labour component. As noted in footnote 68 on page 36 of the TFP report: *"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."*

For the US peers, their O&M costs were deflated using the Employment Cost Index ("ECI") from the US Bureau of Labor Statistics for the labour component and the Gross Domestic Product Price Index ("GDP-PI") from the US Bureau of Economic Analysis for the non-labour component.

g) Please refer to the ‘Can O&M price indexes’ tab (columns H, I, and K) in the TFP working paper for the physical model filed in Ex. L-A1-Staff-002, where the requested information can be obtained.

SEC Interrogatory #020

Interrogatory

Reference:
A1-3-2, Attachment 2

Question(s):

With respect to the LEI, *Empirical Analysis of Total Factor Productivity Trends in the North American Hydroelectric Generation Industry* Report:

a) [p.46] Please explain why, if the revenue of an entity (like OPG) is driven by inflation and TFP, the exogenous method is not a circular calculation.

b) [p. 50, 51] Please describe what steps, if any, were taken by LEI to confirm that the volatility in Figures 26 and 27 is the result of volatility in either weather or hydrology.

c) [p.52] Please describe how LEI has taken into account differences in operating characteristics of hydroelectric facilities, such as storage vs. run-of-the-river, flood control uses, peak demand focus, etc. To what extent, if any, is the OPG hydroelectric fleet operated in a similar manner to the hydroelectric fleets of the peer group? To what extent, if any, does the fixed and mostly inflexible production from nuclear in Ontario have an impact on the productivity of the OPG hydroelectric business?

d) [p.54] Please provide a fitted trend line for each of the capital input quantity indices in Figure 32.

Response

This response was prepared by London Economics International LLC ("LEI")

a) Capital cost input shares may be estimated using two methods, an endogenous or an exogenous approach. LEI tested both approaches and confirmed that the choice does not materially impact the TFP results. As noted on page 46 of the TFP report:

> "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."

b) The year over year volatility in Figure 26 is primarily due to the variability in annual hydroelectric output, as noted on page 50 of the TFP report: *"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."* Nonetheless, the 22-year study timeframe (2002-2023) covers a sufficiently long timeframe that a range of annual hydroelectric output (and underlying conditions) is captured.

LEI also sought to control for any weather-related biases at the endpoints of the study timeframe in determining the long-term TFP trend by supplementing the long run analysis of TFP growth with the trend regression method, as discussed on page 21 of the TFP report:

> *"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."*

c) LEI acknowledges there are diverse power plant designs, and that OPG and other hydroelectric operators have plants of various designs in their fleet. Moreover, LEI notes that operating profiles of the generators are captured indirectly in the annual energy production measure (which is used for output) and also in the MCR measure under the physical method (where we use MCR as a proxy for capital quantity).

d) LEI has not performed such an analysis, but the data is available in the workpapers for SEC to do such analysis if it so desires. Please refer to the 'TFP_Calcs' tab in the TFP working papers filed in Ex. L-A1-Staff-002 for the physical model and monetary model, where the requested information can be obtained for the capital input quantity indices. Specifically, refer to cells C35:C56, ensuring the 'FERC Peers + OPG' peer group is selected in the dropdown in cell C2.

SEC Interrogatory #021

Interrogatory

Reference:
A1-3-2, Attachment 3

Question(s):

With respect to the LEI, *Benchmarking the Costs of Hydroelectric Generation Companies In North America* Report:

a) [p. 5, 18] Please explain the difference, if any, between using a four year period to compare the performance of plants, vs. using the four-year period to validate the relationship between dependent and independent variables.

b) [p.7, 19] Please explain the causal relationship between ownership and costs. What are the aspects of differing ownership (size of entity, public sector vs. private sector, type of regulation, etc.) that cause costs to be different? What investigations has LEI done to determine the nature and quantum of those causal relationships?

c) [p. 13, 21] Please explain why the independent variable "two or less active units" is used (as opposed to three, or five, for example), and why the variable is treated as binary rather than variable with the number or size of the units.

d) [p.13] Please compare the labour and non-labour components in this study with the inflation and TFP studies.

e) [p.13] Please confirm that the OM&A and Capital price indices in this study are static (point in time) numbers rather than rate of change or trend numbers.

f) [p. 13] Please provide a complete list of the independent variables tested and the reasons for their acceptance or rejection. Please provide a detailed explanation of any operating parameters (run of the river vs. storage, dispatch order, environmental restrictions, etc.) that were tested as independent variables.

Response

This response was prepared by London Economics International LLC ("LEI")

a) The econometric model uses four years of data to fit a statistically significant relationship between the dependent and independent variables. LEI selected

independent variables that are meaningful and statistically significant. This process concluded with estimated individual coefficients for each independent variable in the model, which 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. To this point, as noted on pages 21-22 of the benchmarking report:

> *"Econometric tests showed that the linear fit of both models was good. The coefficient of correlation (i.e., the "adjusted R-squared" or "adjusted R2") measures the dispersion of the data around the line-of-best-fit. The R2 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 R2 of 0 implies that there is no correlation that can be explained by the line-of-best-fit. R2 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 R2 values for LEI's OM&A and OM&A + SC models are 0.784 and 0.733, respectively … indicating a good linear fit for each of the models."*

Once the econometric model is fitted, then the fixed effects variable allows for comparison of cost performance across owners of the plants for this four-year period. Therefore, the fixed effects variable allows for comparison of "performance" by owner.

b) With regards to the dimensions of "ownership" mentioned in the question, LEI did factor in the scale of operations as part of the benchmarking study. Specifically, LEI controlled the impact on costs from the size of the plant measured in MW. This scale factor was included as an independent variable in both the OM&A and OM&A + SC models. LEI did not investigate other factors related to business structure and regulation on cost performance.

c) Please see response to IR L-A1-Staff-287 part (a)(i).

d) LEI understands this question to relate to the O&M labour and non-labour price indices used. Please see response to L-A1-SEC-019 part (f), which was answered with regards to the TFP study but also applies to the benchmarking study.

e) No, the price indices change by year. Please see response to IR L-A1-Staff-282 part (a).

f) Please see response to IR L-A1-Staff-286 part a)i.

SEC Interrogatory #022

Interrogatory

Reference:
A1-3-2, Attachment 3

Question(s):

With respect to the LEI, *Benchmarking the Costs of Hydroelectric Generation Companies In North America* Report:

a) [p.17] Please provide the results of this benchmarking study if environmental and regulatory costs are included.

b) [p.18] Please provide the number of plants studied that are owned by OPG (either directly or indirectly).

c) [p. 21] Please provide the results of this benchmarking study if OM&A prices are not included as an independent variable in the model.

d) [p. 25] Please provide the actual cost (OM&A and OM&A+SC) per unit of output (MWh) of each of the plants included in the study (including the size of the plants, and whether they are OPG plants, other Canadian plants, or American plants, but no other identifying features).

Response

This response was prepared by London Economics International LLC ("LEI")

a) This is a request to change the benchmarking models and rerun the analysis. LEI has not conducted this analysis and does not consider this request to be appropriate for a benchmarking study as it would not provide meaningful results. As noted on page 12 of the benchmarking report:

> *"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."*

Further, this request would take a non-trivial amount of time and effort to complete.

b) Please see response to IR L-A1-Staff-282 part (g)(i).

c) This is a request to change the benchmarking models and rerun the analysis. LEI has not conducted this analysis and does not consider this request to be appropriate for a benchmarking study. As noted on page 21 of the benchmarking report:

> *"The **OM&A price** … 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"*

Further, this request would take a non-trivial amount of time and effort to complete.

d) LEI cannot accommodate this request because this data is subject to an NDA between EUCG and LEI. All data used in the analysis that is not covered by the NDA has already been provided in the benchmarking workpaper.

Board Staff Interrogatory #002

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 1
Ref 2: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 2
Ref 3: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 3
Ref 4: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1
Ref 5: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 4

Preamble:

References 1-5 are expert reports filed with the Applicants' pre-filed evidence.

References 1, 2, and 3 are reports filed by London Economics International, LLC, relating to Inflation Factor options, Total Factor Productivity benchmarking, and hydroelectric cost benchmarking.

Reference 4 is the common equity ratio study from Concentric Energy Advisors.

Reference 5 is the ScottMadden study of factors impacting total generation cost with normalizing adjustments relating to OPG Nuclear.

Question(s):

a) Please provide all underlying work files (including underlying database files, spreadsheets, program code, or other underlying documentation) used to produce the tables, figures, and calculations presented in each of the reports referred to above.

Response

a) The Applicants confirm that the information listed in Chart 1 below was provided to OEB staff on a confidential basis as requested. This information is now also in live format as attachments to this response (confidential).

Chart 1 - Workpapers

Document Name	Attachment #
LEI Benchmarking Workpapers	Attachment 1 (Confidential)
LEI I-factor working papers	Attachment 2 (Confidential)
LEI Monetary Model - OPG industry TFP model	Attachment 3 (Confidential)
LEI Physical Model - OPG industry TFP model	Attachment 4 (Confidential)
1 - CEA Exhibits - Actual Equity Ratio Analysis Workpaper	Attachment 5 (Confidential)
2 - CEA Exhibits - Authorized Equity Ratio Analysis Workpaper	Attachment 6 (Confidential)
3 - CEA Exhibits - Credit Metric Analysis Workpaper	Attachment 7
4 - CEA Exhibits - Excel Format	Attachment 8
5 - CEA Exhibits - Proxy Group Screening Workpaper	Attachment 9 (Confidential)
6 - CEA Fig 3 Nuclear Hydro Workpaper	Attachment 10
7 - CEA Fig 4 Value of Generation Output Workpaper	Attachment 11
8 - CEA Fig 5, 7, 8 CapEx Workpaper	Attachment 12
9 - CEA Fig 9 Peer CapEx Workpaper	Attachment 13
10 - CEA Fig 11-12 OPG & Utility Index Spread Workpaper	Attachment 14
11 - CEA Fig 18 Regulatory Mechanisms Workpaper	Attachment 15 (Confidential)
12 - CEA Fig 19 Asset Mix Workpaper	Attachment 16 (Confidential)
13 - CEA Fig 20 Generation Capacity Workpaper	Attachment 17 (Confidential)
SM Cost Model - With Formulas - BWR Base v4 (For OEB)	Attachment 18 (Confidential)
SM Master Data Adjusted For 0 Generation – ORIGINAL	Attachment 19 (Confidential)
SM OPG Regression Analysis v0.07 (For OEB)	Attachment 20 (Confidential)

Exhibit L-A1-Staff-002, Attachment 1

London Economics International, LLC
Benchmarking Workpapers

This Attachment was filed as confidential information in its entirety.

Exhibit L-A1-Staff-002, Attachment 2

London Economics International, LLC
I-factor working papers

This Attachment was filed as confidential information in its entirety.

Exhibit L-A1-Staff-002, Attachment 3

London Economics International, LLC
Monetary Model - OPG industry TFP model

This Attachment was filed as confidential information in its entirety.

Exhibit L-A1-Staff-002, Attachment 4

London Economics International, LLC
Physical Model - OPG industry TFP model

This Attachment was filed as confidential information in its entirety.

Exhibit L-A1-Staff-002, Attachment 5

Concentric Energy Advisors
Exhibits - Actual Equity Ratio Analysis Workpaper

This Attachment was filed as confidential information in its entirety.

Exhibit L-A1-Staff-002, Attachment 6

Concentric Energy Advisors Exhibits
Authorized Equity Ratio Analysis Workpaper

This Attachment was filed as confidential information in its entirety.

Exhibit L-A1-Staff-002, Attachment 9

Concentric Energy Advisors Exhibits
Proxy Group Screening Workpaper

This Attachment was filed as confidential information in its entirety.

Exhibit L-A1-Staff-002, Attachment 15

Concentric Energy Advisors Exhibits
Fig 18 Regulatory Mechanisms Workpaper

This Attachment was filed as confidential information in its entirety.

Exhibit L-A1-Staff-002, Attachment 16

Concentric Energy Advisors Exhibits
Fig 19 Asset Mix Workpaper

This Attachment was filed as confidential information in its entirety.

Exhibit L-A1-Staff-002, Attachment 17

Concentric Energy Advisors Exhibits
Fig 20 Generation Capacity Workpaper

This Attachment was filed as confidential information in its entirety.

Exhibit L-A1-Staff-002, Attachment 18

ScottMadden
Cost Model - With Formulas - BWR Base v4 (For OEB)

This Attachment was filed as confidential information in its entirety.

Exhibit L-A1-Staff-002, Attachment 19

ScottMadden
Master Data Adjusted For 0 Generation – ORIGINAL

This Attachment was filed as confidential information in its entirety.

Exhibit L-A1-Staff-002, Attachment 20

ScottMadden
OPG Regression Analysis v0.07 (For OEB)

This Attachment was filed as confidential information in its entirety.

Board Staff Interrogatory #003

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / pp. 9-11

Preamble:

For the years 2028-2031, OPG proposes that its hydroelectric payment amount be adjusted annually according to a mechanistic custom price-cap adjustment, using a formula that includes an Inflation Factor.

OPG suggested that to calculate its proposed Inflation Factor, OPG uses the same sub-indices from Statistics Canada that the OEB uses when determining the inflation factor for electricity distributors and electricity transmitters, as follows:

• Canadian Gross Domestic Product Implicit Price Index – Final Domestic Demand (GDP IPI FDD)
• Average Weekly Earnings for Ontario – Industrial Aggregate (Ontario AWE)

However, in the current proceeding, OPG is requesting OPG-specific weightings to its proposed Inflation Factor. In "Chart 3 – Summary of Hydroelectric I-Factor Weighting", OPG is proposing a non-labour weight of 84.7% and a labour weight of 15.3%.

OEB staff has prepared the following "Table 1 – Summary of Inflation Factor Weightings", which summarizes the OEB's policy for electricity distributors and transmitters, as well as OPG's proposal.

Table 1 – Summary of Inflation Factor Weightings

	OEB Policy – Weightings Electricity Distributors	**OEB Policy – Weightings Electricity Transmitters**	**OPG Proposed Weightings**
Non-Labour	70%	86%	84.7%
Labour	30%	14%	15.3%
Total	100%	100%	100%

Question(s):

a) Please confirm that “Table 1 – Summary of Inflation Factor Weightings” is accurate. Please update the table as applicable and explain any changes made.

Response

a) OPG confirms that the “OPG Proposed Weightings” column is accurate, as presented in Ex. A1-3-2, p. 11, Chart 3, and in Ex. A1-3-2, Attachment 1, p. 16.

In respect of the two “OEB Policy – Weightings” columns, OPG has reviewed the OEB’s June 11, 2025 letter regarding 2026 Inflation Parameters, and OPG acknowledges that the weightings presented in Table 1 to this interrogatory are consistent with the letter.

Board Staff Interrogatory #004

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / pp. 10 & 11
Ref 2: OEB Letter, 2026 Inflation Parameters, June 11, 2025
Ref 3: EB-2021-0212, OEB 2022 IPI Generic Proceeding, Procedural Order No. 1, Fact Sheet, August 27, 2021

Preamble:

In the tables below, OEB staff has calculated the 2027 Inflation Factors using the weighting for electricity distribution, transmission, and as proposed by OPG.

OEB staff has relied on the following data from Statistics Canada which the OEB uses to calculate the Inflation Factors for electricity distribution and transmission:

- GDP-IPI (FDD): Statistics Canada, Table 36-10-0106-01 (formerly CANSIM 380-0066) - Price Indexes, gross domestic product, quarterly (2017 = 100 unless otherwise noted) - 2025 Q4, data accessed March 3, 2026
- Average Weekly Earnings (AWE): Statistics Canada, Table 14-10-0204-01 (formerly CANSIM 281-0027), Ontario, Industrial aggregate excluding unclassified businesses, annual (current dollars), data accessed March 3, 2026

OEB staff notes that the AWE represents annual data and will be updated in late March 2026 by Statistics Canada.

OEB staff observes that the OEB typically uses the logarithmic growth rate in its calculations, as noted in the OEB Letter, 2026 Inflation Parameters, June 11, 2025, Appendix. As set out in the EB-2021-0212, OEB 2022 IPI Generic Proceeding, Procedural Order No. 1, Fact Sheet, August 27, 2021, the calculations of the “Annual % Change”… are based on the logarithmic growth rate, as opposed to the arithmetic growth rate.

Table 1 – Distribution - Inflation Factor for 2027 Rate Year - Will Be Subject to Change

Inputs and Assumptions												
		Non-Labour GDP-IPI (FDD) - National							Labour AWE- All Employees - Ontario			Resultant Values - Annual Growth for the 2-factor IPI
Rate Year	Calendar Year	Q1	Q2	Q3	Q4	Annual	Annual % Change	Weight	Annual	Annual % Change	Weight	Annual % Change
	2024	123.0	124.4	125.4	126.1	124.725			1,232.27			
2027	2025	127.3	127.8	128.6	129.5	128.300	2.8%	70%	1,293.52	4.9%	30%	3.4%

Table 2 – Transmission - Inflation Factor for 2027 Rate Year - Will Be Subject to Change

Inputs and Assumptions												
		Non-Labour GDP-IPI (FDD) - National							Labour AWE- All Employees - Ontario			Resultant Values - Annual Growth for the 2-factor IPI
Rate Year	Calendar Year	Q1	Q2	Q3	Q4	Annual	Annual % Change	Weight	Annual	Annual % Change	Weight	Annual % Change
	2024	123.0	124.4	125.4	126.1	124.725			1,232.27			
2027	2025	127.3	127.8	128.6	129.5	128.300	2.8%	86%	1,293.52	4.9%	14%	3.1%

Table 3 – OPG - Inflation Factor for 2027 Rate Year - Will Be Subject to Change

Inputs and Assumptions												
		Non-Labour GDP-IPI (FDD) - National							Labour AWE- All Employees -			Resultant Values - the 2-factor IPI
Rate Year	Calendar Year	Q1	Q2	Q3	Q4	Annual	Annual % Change	Weight	Annual	Annual % Change	Weight	Annual % Change
	2024	123.0	124.4	125.4	126.1	124.725			1,232.27			
2027	2025	127.3	127.8	128.6	129.5	128.300	2.8%	84.7%	1,293.52	4.9%	15.3%	3.1%

Question(s):

a) Please confirm that the following tables are accurate. Please update the tables as applicable and explain any changes made.

- Table 1 - Distribution - Inflation Factor for 2027 Rate Year
- Table 2 - Transmission - Inflation Factor for 2027 Rate Year
- Table 3 - OPG - Inflation Factor for 2027 Rate Year

b) Please update the above-noted tables (or any revised tables) with the AWE data that will be updated in late March 2026 by Statistics Canada.

Response

a) The Applicants have reviewed Tables 1-3 and understand the calculations as follows:

- Non-labour component (GDP-IPI FDD) is the annual percentage change from 2024 to 2025 determined using a logarithmic growth rate
- Labour component (AWE) is the annual percentage change from 2023 to 2024 determined using a logarithmic growth rate

The labour component annual change in Tables 1-3 is consistent with the OEB Letter noted as Reference 2, and consistent with the annual change provided in Ex. I1-2-1, Table 1, line 2, col. (a).

The non-labour component annual change in Tables 1-3 is based on information updated more recently than that provided in the OEB Letter noted as Reference 2. In Ex. I1-2-1, Table 1, line 3, col. (a), OPG calculated an annual change of 3.24%, consistent with Table 1 in the OEB Letter.

For purposes of responding to this question, the Applicants can confirm that calculating an annual change using the formula [ln(128.3)-ln(124.725)] results in 2.8%, as presented in Tables 1-3.

Based on the annual percentage changes and weightings provided in the tables, the Applicants confirm that the resulting inflation factor percentages are calculated correctly.

b) Chart 1 to 3, below, are updated for 2025 AWE data, accessed by the Applicants on March 30, 2026.

Chart 1
Distribution Inflation Factor Calculation

Year	Inputs and Assumptions										
	Non-Labour GDP-IPI (FDD) - National							Labour AWE - All Employees - Ontario			Composite Index
	Q1	Q2	Q3	Q4	Annual	Annual % Change	Weight	Annual	Annual % Change	Weight	Annual % Change
2024	123.0	124.4	125.4	126.1	124.725			1292.6			
2025	127.3	127.8	128.6	129.5	128.300	**2.8%**	**70.0%**	1,339.7	**3.6%**	**30.0%**	**3.1%**

Chart 2
Transmission Inflation Factor Calculation

Year	Inputs and Assumptions										
	Non-Labour GDP-IPI (FDD) - National							Labour AWE - All Employees - Ontario			Composite Index
	Q1	Q2	Q3	Q4	Annual	Annual % Change	Weight	Annual	Annual % Change	Weight	Annual % Change
2024	123.0	124.4	125.4	126.1	124.725			1292.6			
2025	127.3	127.8	128.6	129.5	128.300	**2.8%**	**86.0%**	1,339.7	**3.6%**	**14.0%**	**2.9%**

Chart 3
OPG Inflation Factor Calculation

Year	Inputs and Assumptions										
	Non-Labour GDP-IPI (FDD) - National							Labour AWE - All Employees - Ontario			Composite Index
	Q1	Q2	Q3	Q4	Annual	Annual % Change	Weight	Annual	Annual % Change	Weight	Annual % Change
2024	123.0	124.4	125.4	126.1	124.725			1,292.6			
2025	127.3	127.8	128.6	129.5	128.300	**2.8%**	**84.7%**	1,339.7	**3.6%**	**15.3%**	**2.9%**

Board Staff Interrogatory #005

Interrogatory

Reference:
Ref 1: EB-2016-0152, Decision and Order, December 28, 2017, p. 122
Ref 2: Exhibit A1 / Tab 3 / Schedule 2 / pp. 1, 10 & 11
Ref 3: Exhibit I1 / Tab 1 / Schedule 1 / Table 1
Ref 4: Exhibit A1 / Tab 3 / Schedule 2 / p. 36

Preamble:

In OPG's payments amounts for 2017-2021, the OEB approved weights of 88% non-labour and 12% labour for OPG. 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.

OEB staff notes that the impact of OPG's proposal to use OPG-specific weightings for non-labour and labour have both an immaterial impact and zero impact. This is as compared with the OEB's standard weights for electricity distributors and electricity transmitters, respectively, on OPG's proposed 2027 Revenue Requirement for Regulated Hydroelectric. Please see OEB staff's tables below that calculate the immaterial and zero impacts.

OPG noted that its materiality threshold is $20 million.

Table 1 – Calculation of Immaterial Impacts using OPG Specific Weights Compared to Electricity Distributor Weights for 2027 Rate Year

OEB staff calculated Inflation Factor Using OPG-Specific Weights	3.1%
Less: OEB staff calculated Inflation Factor Using Dx-Specific Weights	3.4%
Difference - Equals an approximate net impact of 0.3% on OPG's revenue requirement	-0.3%
2027 Revenue Requirement - Regulated Hydroelectric ($M) - Exhibit I1 / Tab 1 / Schedule 1 / Table 1	$1,630,407,512
Approximate net impact of 0.3% on OPG's revenue requirement	($4,891,223)
OPG's materiality threshold - Exhibit A1 / Tab 3 / Schedule 2 / p. 36	$20,000,000

Table 2 – Calculation of Zero Impacts using OPG-Specific Weights Compared to Electricity Transmitter Weights for 2027 Rate Year

OEB staff calculated Inflation Factor Using OPG-Specific Weights	3.1%
Less: OEB staff calculated Inflation Factor Using Tx-Specific Weights	3.1%
Difference - Equals an approximate net impact of 0.0% on OPG's revenue requirement	0.0%
2027 Revenue Requirement - Regulated Hydroelectric ($M) - Exhibit I1 / Tab 1 / Schedule 1 / Table 1	$1,630,407,512
Approximate net impact of 0.0% on OPG's revenue requirement	$0
OPG's materiality threshold - Exhibit A1 / Tab 3 / Schedule 2 / p. 36	$20,000,000

Question(s):

a) Please confirm that the following tables are accurate. Please update the tables as applicable and explain any changes made.
   - Table 1 – Calculation of Immaterial Impacts using OPG-Specific Weights Compared to Electricity Distributor Weights for 2027 Rate Year
   - Table 2 – Calculation of Zero Impacts using OPG-Specific Weights Compared to Electricity Transmitter Weights for 2027 Rate Year

b) Please update the above-noted tables (or any revised tables) with the Average Weekly Earnings (AWE) data that will be updated in late March 2026 by Statistics Canada.

c) Please elaborate whether OPG agrees or disagrees with OEB staff's demonstration that the impact of OPG's proposal to use OPG-specific weightings has both an immaterial impact and zero impact on OPG's 2027 revenue requirement for hydroelectric, when compared to electricity distributors and transmitters, respectively.

d) Please provide an OEB precedent (including EB#) where the OEB approved different weightings for the Inflation Factor calculations, other than the generic weights approved by the OEB for electricity distribution and transmission, and the OPG EB-2016-0152 Decision and Order.

Response

a) The Applicants confirm the following:
   - OEB staff calculated inflation factor using OPG-specific weights (3.1%) is consistent with Ex. L-Staff-004, Table 3.
   - OEB staff calculated inflation factor using Dx specific weights (3.4%) is consistent with Ex. L-Staff-004, Table 1.

- OEB staff calculated inflation factor using Tx specific weights (3.1%) is consistent with Ex. L-Staff-004, Table 2.
- OEB staff's reference to 2027 Revenue Requirement is incorrectly using Ex. I1-1-1, Table 1, line 23 ($1,630.4M); it should be line 21 ($1,668.3M).

Updated Charts are provided below.

Chart 1
Calculation of Immaterial Impacts Using OPG-Specific Weights Compared to Electricity Distributor Weights for 2027 Rate Year

OEB Staff calculated Inflation Factor Using OPG-Specific Weights		3.1%
Less: OEB staff calculated Inflation Factor using Dx-Specific Weights		3.4%
Difference - Equals an approximates net impact of 0.3% on OPG's revenue requirement		-0.3%
2027 Revenue Requirement - Regulated Hydroelectric ($M) - Exhibit I1 / Tab 1/ Schedule 1 / Table 1 / line 21	$	1,668,343,531
Approximate net impact of 0.3% on OPG's revenue requirement		($5,005,031)
OPG's materiality threshold - Exhibit A1 / Tab 3 / Schedule 2 / p. 36	$	20,000,000

Chart 2
Calculation of Immaterial Impacts Using OPG-Specific Weights Compared to Electricity Transmitter Weights for 2027 Rate Year

OEB Staff calculated Inflation Factor Using OPG-Specific Weights		3.1%
Less: OEB staff calculated Inflation Factor using Tx-Specific Weights		3.1%
Difference - Equals an approximates net impact of 0.0% on OPG's revenue requirement		0.0%
2027 Revenue Requirement - Regulated Hydroelectric ($M) - Exhibit I1 / Tab 1/ Schedule 1 / Table 1 / line 21	$	1,668,343,531
Approximate net impact of 0.0% on OPG's revenue requirement		$0
OPG's materiality threshold - Exhibit A1 / Tab 3 / Schedule 2 / p. 36	$	20,000,000

b) Charts 3 and 4, below, are updated for 2025 AWE data, accessed by the Applicants on March 30, 2026.

Chart 3
Calculation of Immaterial Impacts Using OPG-Specific Weights Compared to Electricity Distributor Weights for 2027 Rate Year (Updated AWE)

Recalculated Inflation Factor Using OPG-Specific Weights (Updated AWE)		2.9%
Less: Recalculated Inflation Factor Using Dx-Specific Weights (Updated AWE)		3.1%
Difference - Equals an approximates net impact of 0.3% on OPG's revenue requirement		-0.2%
2027 Revenue Requirement - Regulated Hydroelectric ($M) - Exhibit I1 / Tab 1/ Schedule 1 / Table 1 / line 21	$	1,668,343,531
Approximate net impact of 0.3% on OPG's revenue requirement		($3,336,687)
OPG's materiality threshold - Exhibit A1 / Tab 3 / Schedule 2 / p. 36	$	20,000,000

Witness Panel: Finance, D&V, Cost of Capital, Regulatory Constructs, Customer Impacts

Chart 4
Calculation of Immaterial Impacts Using OPG-Specific Weights Compared to Electricity Transmitter Weights for 2027 Rate Year (Updated AWE)

Recalculated Inflation Factor Using OPG-Specific Weights (Updated AWE)		2.9%
Less: Recalculated Inflation Factor Using Tx-Specific Weights (Updated AWE)		2.9%
Difference - Equals an approximates net impact of 0.0% on OPG's revenue requirement		0.0%
2027 Revenue Requirement - Regulated Hydroelectric ($M) - Exhibit I1 / Tab 1/ Schedule 1 / Table 1 / line 21	$	1,668,343,531
Approximate net impact of 0.0% on OPG's revenue requirement		$0
OPG's materiality threshold - Exhibit A1 / Tab 3 / Schedule 2 / p. 36	$	20,000,000

c) The Applicants understand the calculations performed by OEB staff but disagrees with characterizing as an "impact of OPG's proposal". This characterization implies that the weightings applicable to electricity distributors and/or transmitters should be considered as the base standard, and that OPG is proposing to deviate from that standard. In fact, OPG is a generator that is proposing to adopt a generation-industry inflation factor recommended by London Economics International LLC, consistent with the approach adopted in EB-2016-0152.

d) The Applicants are unaware of OEB precedents on this issue, but notes that OPG has been the only generator subject to rate regulation by the OEB prior to the filing of this application.

Board Staff Interrogatory #006

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 4 / Schedule 4

Preamble:

At Reference 1, it is stated that DNNP LP is expected to be the OEB-licence holder for the Darlington New Nuclear Program (DNNP) facilities.

Question(s):

a) Please outline and describe the Applicants' plan for an OEB Generation Licence for the Darlington New Nuclear Program facilities.

Response

a) Exhibit A1-4-4, Section 2.0, provides an overview of the relationship between DNNP LP and OPG in relation to the DNNP facilities. Based on this relationship, OPG will be preparing an application for a new generation licence authorizing DNNP LP (by its General Partner) as the operator of the new Unit 1 generation facility. In parallel, OPG will prepare an application for an amendment to OPG's existing generation licence to add authorization as the owner of the new generation facility. OPG will continue to hold the CNSC licence and operate the facility on behalf of DNNP LP. Both applications are targeted to be filed in Q2 of 2026.

Board Staff Interrogatory #007

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 4 / Schedule 2 / Chart 1
Ref 2: EB-2013-0321, Exhibit A1 / Tab 4 / Schedule 2

Preamble:

At Reference 1, OPG lists the prescribed hydroelectric generating stations with, among other things, the net in-service installed capacity for each. Reference 2 provides the same type of information at the time of the EB-2013-0321 proceeding.

Question(s):

a) Please confirm the following table correctly compiles the information from References 1 and 2. Please correct any data errors. Please add data to the final column to identify the expected net in-service installed capacity for each prescribed hydroelectric generating station by the end of 2031:

Table 1 – List of Prescribed Hydroelectric Generating Stations with In-Service Capacity (MW)

Region	Generating Station	In-Service Capacity EB-2013-0321 (MW)	In-Service Capacity EB-2025-0297 (MW)	Planned In-Service Capacity at end of 2031 according to Capital Plan in EB-2025-0297 (MW)
Eastern	Abitibi Canyon	349	344.8	
	Arnprior	82	81.6	
	Barrett Chute	176	176.1	
	Bingham Chute	1	1	
	Calabogie	5	10.7	
	Chats Falls	96	96	
	Chenaux	144	143.7	
	Chute	3	2.9	
	Coniston	5	2.7	
	Crystal Falls	8	8.4	

Witness Panel: Hydroelectric Operations and Hydroelectric Projects, and Market Renewal Program

Region	Generating Station	In-Service Capacity EB-2013-0321 (MW)	In-Service Capacity EB-2025-0297 (MW)	Planned In-Service Capacity at end of 2031 according to Capital Plan in EB-2025-0297 (MW)
	Des Joachims	429	428.8	
	Elliott Chute	2	1.6	
	Lower Notch	274	274.2	
	Matabitchuan	10	9.6	
	McVittie	3	2.8	
	Mountain Chute	170	170.2	
	Nipissing	2	0	
	Otter Rapids	182	182.4	
	Otto Holden	243	242.8	
	R.H. Saunders	1045	1045	
	Stewartville	182	182.1	
	Stinson		5.4	
Western	Aguasabon	51	47.1	
	Alexander	69	68.9	
	Auburn	2	1.9	
	Big Chute	10	10	
	Big Eddy	8	8	
	Cameron Falls	92	91.6	
	Caribou Falls	91	91.3	
	Eugenia	6	6.1	
	Frankford	3	2.6	
	Hagues Reach	4	3.6	
	Hanna Chute	1	1.4	
	High Falls	3	2.7	
	Kakabeka Falls	25	24.6	
	Lakefield	2	1.8	
	Manitou Falls	73	73.1	
	Merrickville	2	1.7	
	Meyersburg	5	5.2	
	Pine Portage	142	145.9	

Region	Generating Station	In-Service Capacity EB-2013-0321 (MW)	In-Service Capacity EB-2025-0297 (MW)	Planned In-Service Capacity at end of 2031 according to Capital Plan in EB-2025-0297 (MW)
	Ragged Rapids	8	8.3	
	Ranney Falls	10	19.5	
	Seymour	6	5.7	
	Sidney	4	4.4	
	Sills Island	2	1.8	
	Silver Falls	48	52.4	
	South Falls	4	5.9	
	Trethewey Falls	1.7	1.8	
	Whitedog Falls	69	67.8	
Niagara	DeCew Falls 1	23	22.8	
	DeCew Falls 2	144	144	
	Sir Adam Beck 1	427	557.9	
	Sir Adam Beck 2	1499	1499.2	
	Sir Adam Beck PGS	174	174	

b) Please list all the generating stations from part a) that have had a realized efficiency gain from the EB-2013-0321 proceeding to the end of 2025.

c) Please list all the generating stations from part a) that are expected to realize an efficiency gain from 2026 to the end of 2031.

Response

a) OPG confirms the table accurately compiles the information from Reference 1 (Ex. A1-4-2, Chart 1).

OPG confirms the table accurately compiles the information from Reference 2 (EB-2013-0321, Ex. A1-4-2, Chart 2) with the exception of the Stinson GS and the Whitedog Falls GS. These entries have been corrected in the revised table below.

In the last column, the planned Maximum Continuous Rating ("MCR") for each regulated hydroelectric generating station as of December 31, 2031 is provided. This estimated incremental capacity is entirely associated with refurbishment and redevelopment projects. The MCR values will be validated following commissioning, performance testing, and confirmation of applicable operating limits.

Chart 1 – List of Prescribed Hydroelectric Generating Stations with In-Service Capacity (MW)

Region	Generating Station	In-Service Capacity EB-2013-0321[1] (MW)	In-Service Capacity EB-2025-0297 (MW)	Planned In-Service Capacity (MCR) at end of 2031 according to Capital Plan in EB-2025-0297 (MW)
Eastern	Abitibi Canyon	349	344.8	344.8
	Arnprior	82	81.6	81.6
	Barrett Chute	176	176.1	176.1
	Bingham Chute	1	1.0	2.0
	Calabogie	5	10.7	10.7
	Chats Falls	96	96.0[2]	96.0
	Chenaux	144	143.7	143.7
	Chute	3	2.9	2.9
	Coniston	5	2.7	6.0
	Crystal Falls	8	8.4	8.4
	Des Joachims	429	428.8	428.8
	Elliott Chute	2	1.6	1.6
	Lower Notch	274	274.2	274.2
	Matabitchuan	10	9.6	12.0
	McVittie	3	2.8	2.8
	Mountain Chute	170	170.2	170.2
	Nipissing	2	0[3]	0
	Otter Rapids	182	182.4	203.5
	Otto Holden	243	242.8	250.4
	R.H. Saunders	1045	1045.0	1059.0

Region	Generating Station	In-Service Capacity EB-2013-0321[1] (MW)	In-Service Capacity EB-2025-0297 (MW)	Planned In-Service Capacity (MCR) at end of 2031 according to Capital Plan in EB-2025-0297 (MW)
	Stewartville	182	182.1	183.5
	Stinson	6	5.4	6.0
Western	Aguasabon	51	47.1	47.1
	Alexander	69	68.9	68.9
	Auburn	2	1.9	1.9
	Big Chute	10	10.0	10.0
	Big Eddy	8	8.0	8.0
	Cameron Falls	92	91.6	92.5
	Caribou Falls	91	91.3	91.3
	Eugenia	6	6.1	6.1
	Frankford	3	2.6	2.6
	Hagues Reach	4	3.6	3.6
	Hanna Chute	1	1.4	1.4
	High Falls	3	2.7	2.7
	Kakabeka Falls	25	24.6	27.4
	Lakefield	2	1.8	1.8
	Manitou Falls	73	73.1	73.1
	Merrickville	2	1.7	1.7
	Meyersburg	5	5.2	5.2
	Pine Portage	142	145.9	145.9
	Ragged Rapids	8	8.3	8.3
	Ranney Falls	10	19.5	19.5
	Seymour	6	5.7	5.7
	Sidney	4	4.4	4.4
	Sills Island	2	1.8	1.8
	Silver Falls	48	52.4	52.4
	South Falls	4	5.9	5.9
	Trethewey Falls	1.7	1.8	1.8
	Whitedog Falls	68	67.8	67.8

Region	Generating Station	In-Service Capacity EB-2013-0321[1] (MW)	In-Service Capacity EB-2025-0297 (MW)	Planned In-Service Capacity (MCR) at end of 2031 according to Capital Plan in EB-2025-0297 (MW)
Niagara	DeCew Falls 1	23	22.8	22.8
	DeCew Falls 2	144	144.0	144.0
	Sir Adam Beck 1	427	551.8[4]	563.8
	Sir Adam Beck 2	1499	1499.2	1505.2
	Sir Adam Beck PGS	174	174.0	174.0

Note: Grey cells highlight corrected data.
[1]The in-service capacity numbers as presented in EB-2013-0321 were rounded to the nearest whole number.
[2]Total station installed capacity is 192 MW; OPG is entitled to 50% of the capacity (96 MW) – see Ex. A1-4-2, Section 2.1.
[3]Nipissing GS has no units currently in service.
[4]MCR for Sir Adam Beck 1 GS was updated based on performance test on April 15, 2026.

b) OPG's regulated hydroelectric generating stations that realized efficiency gains from the EB-2013-0321 proceeding to the end of 2025 include: Des Joachims GS, Otter Rapids GS, Pine Portage GS, Ranney Falls GS, Silver Falls GS, South Falls GS, and Sir Adam Beck 1 GS.

c) Planned efficiency gains are estimates based on current planning assumptions and are not guaranteed to be achieved. Efficiency gains will be finalized following commissioning, performance testing, and confirmation of applicable operating limits.

OPG's regulated hydroelectric generating stations that may realize an efficiency gains between 2026 to the end of 2031 include: R.H. Saunders GS, Otter Rapids GS, Otto Holden GS, Stewartville GS, Alexander GS, Cameron Falls GS, Sir Adam Beck 1 GS, Sir Adam Beck 2 GS, Matabitchuan GS, Coniston GS, Stinson GS, Bingham Chute GS, and Kakabeka Falls GS.

Board Staff Interrogatory #008

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 12 / Schedule 1
Ref 2: Exhibit D2 / Tab 1 / Schedule 3 / Attachment 1
Ref 3: EB-2020-0290, Exhibit D2 / Tab 2 / Schedule 3
Ref 4: Exhibit D2 / Tab 2 / Schedule 2 / p. 3

Preamble:

Reference 1 identifies a "Program Scope Review Board" while some Business Case Summaries in Reference 2 make reference to submitting "scope requests" to "the PSRB" to obtain approvals in relation to Refurbishment Outages. Specifically, the PSRB is noted in Tabs 9 and 14 to Reference 2. The same acronym is used in Reference 3, which describes scope planning for the Refurbishment Outages for Units 3, 1, and 4.

In Reference 4, OPG states that all the scope included within the OEB's approval of the $4,800.2 million in-service addition for the refurbishment of Unit 2 was completed.

It is OEB staff's understanding that in executing the Darlington Refurbishment Outages, OPG regularly convened a committee or other such group to manage and approve the scope of work that was executed.

Question(s):

a) Please confirm whether it was the Program Scope Review Board or some other group that was responsible for managing the scope of Darlington Refurbishment Outages. Please provide the OPG governance document that describes this group and includes their authorities and responsibilities as they related to the Refurbishment Outages.

b) Please summarize in plain language the role of the group or board from part a).

c) Please summarize the decisions the group or board from part a) made in relation to each Refurbishment Outage. Please do so with the following details:
i. A count of work orders or work packages added to scope
ii. A count of work orders or work packages removed from scope
iii. A count of requests for work orders or work packages for scope injection that were denied

iv. Group the summary using the Uniform Subject Index or System Classification Index, whichever may be applicable, at a resolution no-coarser than the system level (i.e., unless otherwise not possible, the first three digits of the five-digit system code are non-zero).
v. Please summarize any other decisions this group made in the course of executing the Unit 2 Refurbishment Outage.

Response

a) Confirmed. Over the lifecycle of the Darlington Refurbishment Program, the Program Scope Review Board and associated Change Control Boards were responsible for managing the scope executed within the Darlington Refurbishment Outages. For clarity, this scope includes:
    - Darlington Refurbishment Program scope (i.e., planned and funded within the $12.8 billion program budget).
    - Scope that is not included in the Darlington Refurbishment Program; however, is best executed within the Darlington Refurbishment Outages. This includes scope such as routine cyclical maintenance and other projects.

    The applicable Boards and their governance documents describing their authorities and responsibilities as they related to the Refurbishment Outages are provided below:

    - Attachment 1: Program Scope Review Board Terms of Reference, NK38-PLAN-09701-10003
    - Attachment 2: Change Control Board Terms of Reference, NK38-REF-09701-10008
    - Attachment 3: Program Change Control Board, NK38-REF-09701-10007
    - Attachment 4: Refurbishment Change Control Board, NK38-TOR-09701-00001

b) A summary of the role of each Board identified in response part a) is provided below.

    The Program Scope Review Board (“PSRB”) was established during the early planning stages of the Darlington Refurbishment Program and was active from approximately 2010 to 2015. The PRSB was the primary governing body responsible for establishing the Darlington Refurbishment Program scope, as well as controlling any material scope additions and/or removals from the Darlington Refurbishment Program.

In 2016, the Change Control Board ("CCB") and a Program Change Control Board ("PCCB") were established. The role of these boards was to review, and approve/reject changes associated with scope, cost and/or schedule, that exceeded Project Manager and Project Director authority. If required, the CCB would elevate a change decision to the PCCB. The CCB and/or the PCCB were responsible for reviewing all changes against Darlington Refurbishment Program projects and all work being executed within a Darlington Refurbishment Outage, regardless of funding source.

In 2021, the Refurbishment Change Control Board ("RCCB") was established, consolidating the role of the CCB and PCCB into one forum.

c) i. to iv.

A summary of the decisions made by the Boards identified in part a) in relation to each Darlington Refurbishment Outage is provided in Chart 1 by Unit, and Chart 2 by System Classification Index.

Chart 1 – Work Order Rejections, Additions and Removals by Darlington Refurbishment Outage Unit

Unit	Rejected	Added	Removed
Unit 2	204	230	66
Unit 3	234	149	8
Unit 1	92	106	10
Unit 4	105	113	9
Total	**635**	**598**	**93**

Chart 2 – Work Order Rejections, Additions and Removals by Darlington System Classification Index (SCI)

SCI	Rejected	Added	Removed
012	0	2	0
050	1	0	0
133	0	1	1
135	0	1	0
141	0	1	0
155	0	1	0
211	11	6	5
213	1	1	0
261	1	1	0
311	0	2	0
317	70	20	2

318	0	0	1
321	14	16	1
322	1	0	4
323	1	0	0
325	0	1	0
327	0	1	0
331	34	53	28
332	3	10	0
333	4	8	1
334	8	25	1
335	0	1	0
338	2	5	0
339	0	1	0
341	3	3	0
343	12	3	0
345	0	1	0
347	8	1	0
348	1	5	0
352	6	8	0
353	0	1	0
358	0	6	0
361	5	1	0
367	2	0	1
383	1	7	0
400	1	6	0
411	5	8	3
412	15	7	2
413	0	1	0
415	0	4	0
417	4	7	0
418	4	13	1
421	8	9	0
422	2	0	0
423	7	7	0
424	5	1	0
425	4	4	0
430	2	2	0
432	8	1	0
433	6	1	1
434	0	1	0
435	0	1	0
440	5	5	1

441	9	7	1
442	1	1	0
445	1	0	0
481	1	1	0
482	2	2	0
485	2	0	0
511	1	1	0
515	4	4	2
521	1	3	1
531	4	2	0
532	2	2	0
533	5	23	1
535	9	5	0
553	0	2	1
554	1	0	0
555	5	0	0
557	0	2	0
561	0	1	0
562	3	0	1
563	1	3	0
600	1	0	0
602	2	3	0
610	1	0	0
621	5	2	1
623	1	4	0
630	1	0	0
631	3	4	0
632	4	1	0
633	8	19	2
634	27	26	1
635	9	11	5
636	26	4	0
637	3	5	0
638	10	6	0
640	0	3	0
641	6	7	0
642	4	8	0
643	6	3	0
644	1	2	0
645	1	0	0
646	0	1	0
648	1	3	0

651	0	1	0
653	1	0	0
655	2	0	0
657	3	0	0
658	1	1	0
661	1	1	0
671	2	1	0
672	8	5	0
673	3	8	0
674	1	0	0
675	0	6	1
678	3	3	3
679	25	8	0
682	14	7	2
683	13	8	0
691	4	4	0
711	3	9	0
712	0	1	0
714	1	1	0
715	0	2	0
721	14	6	0
722	4	3	0
723	5	1	0
728	5	3	0
732	36	6	1
736	0	3	0
737	2	2	0
738	0	1	0
739	7	13	0
744	2	0	0
749	1	0	0
751	17	18	5
757	1	0	0
761	7	16	0
780	0	1	0
781	2	14	10
782	8	2	1
791	2	0	1
920	0	1	0
Total	**635**	**598**	**93**

1

v. No additional material decisions were made by the Boards identified in part a) during the course of executing the Unit 2 Darlington Refurbishment Outage beyond those already described in the referenced documents and in the responses to parts a), b) and c).

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Guideline

Internal Use Only	
Document Number: NK38-PLAN-09701-10003	Usage Classification: Information
Sheet Number: N/A	Revision: R003

Title:
DARLINGTON REFURBISHMENT PROGRAM – PROGRAM SCOPE REVIEW BOARD – TERMS OF REFERENCE

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Darlington Refurbishment Program – Program Scope Review Board – Terms of Reference

NK38-PLAN-09701-10003-R003
2018-02-06

Order Number: N/A
Other Reference Number:

Internal Use Only

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Vice President,
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Guideline	Internal Use Only		
	Document Number: NK38-PLAN-09701-10003		Usage Classification: Information
	Sheet Number: N/A	Revision Number: R003	Page: 2 of 5

Title:
DARLINGTON REFURBISHMENT PROGRAM – PROGRAM SCOPE REVIEW BOARD – TERMS OF REFERENCE

Revision Summary

Revision Number	Date	Comments
R000	2010-06-16	Initial issue.
R001	2010-06-30	Re-issued by Planning and Control
R002	2011-02-01	Re-issued to align with screening and funding committees and process improvements documented in NK38-INS-09701-10001 (R002).
R003	2018-02-06	Re-issued to align with Terms of Reference format issued November 23, 2017

Guideline	Internal Use Only		
	Document Number: NK38-PLAN-09701-10003		Usage Classification: Information
	Sheet Number: N/A	Revision Number: R003	Page: 3 of 5

Title:
DARLINGTON REFURBISHMENT PROGRAM – PROGRAM SCOPE REVIEW BOARD – TERMS OF REFERENCE

1.0 OBJECTIVE

The objective of the Program Scope Review Board (PSRB) is to approve new scope additions to and/or scope removals from the Darlington Nuclear Refurbishment (DNR) Program.

2.0 MEETING TIER, SPONSOR, CHAIR

Meeting Tier:
The PSRB is a Tier-1 Meeting requiring NPET and 3 quorum voting members.

Sponsor:
VP, Planning & Controls, Nuclear Project Management Office

Chair:
Director, Planning & Controls, Nuclear Refurbishment

3.0 SUPPLIER

All DNR Project Teams can submit Scope Change Proposals to the PSRB; provided endorsements to do so have been received from the following committees prior:

1.) Technical Screening Committee (TSC).
2.) Funding Screening Committee (FSC).
3.) New Work Screening Committee (NWSC).

4.0 INPUT

1.) Approved Decision Record Analysis Summary (DRAS), which may be validated/reviewed at an Options Review Board (ORB) meeting.
2.) New/Modified Darlington Scope [Change] Request (DSR)
3.) Summary Presentation of Scope Topic (1 to 3-page Power Point Presentation)
4.) Technical Screening Committee (TSC) endorsement to move forward to PSRB
5.) Funding Screening Committee (FSC) endorsement to move forward to PSRB.

5.0 PROCESS

PSRB decides if a given DNR Program Scope Addition and/or Removal Topic will be approved or rejected by way of a Quorum Vote.

In order to record a decision at the PSRB, consensus must be reached between the three (3) voting members of the Quorum. This applies to both scope additions and removals. The PSRB Voting Members will strive to meet the meeting objective of reaching consensus on all scope items during the meeting or, by requesting additional

information be provided by the scope sponsors and initiators in order to support a decision.

6.0 OUTPUT

1.) Endorsement of DRAS.
2.) Approval of DSR.
3.) Approval to proceed with a given scope change proposal.
4.) PSRB Meeting Minutes recording all the above.
5.) Update of Darlington Scope Request (DSR) Database

7.0 CONSUMERS

1.) Project Directors – awareness of decision and impact on their project bundle.
2.) Project Managers – awareness of decision and impact on their project.
3.) Planning & Control Leads – to ensure all changes (scope, cost, schedule) are appropriately processed following PSRB decision.
4.) Vendors – as related to potential adjustments in assigned scope.

8.0 ATTENDEES AND QUORUM

The PSRB Quorum is comprised of the following three (3) Voting Members:

1.) SVP, Nuclear Projects (Deitmar Reiner as of February 06, 2018)
2.) SVP, Nuclear Refurbishment (Mike Allen as of February 06, 2018)
3.) SVP, Nuclear Engineering and Chief Nuclear Engineer (Steve Woods as of February 06, 2018)

In order to record a decision at the PSRB, consensus must be reached between the three (3) voting members of the Quorum. This applies to both scope additions and removals. The PSRB Voting Members will strive to meet the meeting objective of reaching consensus on all scope items during the meeting or, by requesting additional information be provided by the scope sponsors and initiators in order to support a decision.

In the event that a give Quorum Member is not able to attend a scheduled PSRB Meeting, the Quorum Member may delegate his/her chair to an empowered delegate.

In addition to the above Voting Members, the following Non-Voting Members shall be invited to all PSRB Meetings as Sponsors and Advisors in support of Quorum Members:

1.) VP, Engineering, Nuclear Refurbishment
2.) VP, Execution, Nuclear Refurbishment
3.) VP, Science & Tech, or Director, Eng Services (See Note)

4.) Director, Planning and Control, Nuclear Refurbishment
5.) Director, Nuclear Finance

Note: The VP, Science and Technology and Director, Engineering Services shall be responsible for scope recommendations within their respective areas of responsibility and attend as appropriate.

9.0 MEETING FREQUENCY

The PSRB shall convene on an as required basis throughout the program. The frequency of PSRB Meeting's will typically increase at "scope-freeze" points in the DNR Schedule for each Unit.

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Guideline

Internal Use Only	
Document Number: **NK38-REF-09701-10008**	Usage Classification: **Information**
Sheet Number: **N/A**	Revision: **R000**

Title:
TERMS OF REFERENCE FOR THE NUCLEAR REFURBISHMENT CHANGE CONTROL BOARD

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Terms Of Reference For The Nuclear Refurbishment Change Control Board

NK38-REF-09701-10008-R000
2017-12-21

Order Number: N/A
Other Reference Number:

Internal Use Only

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Approved By: Sola Mugaji
Director Project Planning & Control-Execution

Guideline	Internal Use Only		
	Document Number: NK38-REF-09701-10008		Usage Classification: Information
	Sheet Number: N/A	Revision Number: R000	Page: 2 of 5

Title:
TERMS OF REFERENCE FOR THE NUCLEAR REFURBISHMENT CHANGE CONTROL BOARD

Revision Summary

Revision Number	Date	Comments
R000	2017-12-21	Initial issue. Note: This document supersedes record NK38-CORR-09701-0639484

Guideline	Internal Use Only	
	Document Number: NK38-REF-09701-10008	Usage Classification: Information
	Sheet Number: N/A	Revision Number: R000 / Page: 3 of 5

Title:
TERMS OF REFERENCE FOR THE NUCLEAR REFURBISHMENT CHANGE CONTROL BOARD

1.0 OBJECTIVE

Review and approval of changes that exceed Project Manager and Project Director authority and to elevate changes to Program Change Control Board (PCCB) if and when required.

2.0 MEETING TIER

Tier 2 - Project Committee Meetings are cross-functional Meetings held by the Program to perform decision analysis and oversight. Each meeting is sponsored by a Director and chaired by a Manager.

Sponsor: Director Project Planning & Controls - Execution

Chair: Manager, Cost Management, Project Controls

3.0 SUPPLIER

Project Execution Teams and Change Management, Nuclear Projects

4.0 INPUT

Change Control form (CCF) prepared by Project Manager (PM) with support from Project Planning and Control (PP&C) lead to capture cost and schedule impacts and descriptions as well as to identify the potential funding streams.

5.0 PROCESS

5.1 A quorum is the sponsor and three members noted in the Quorum membership list, including the lead of the organization impacted by the change (example, if an Engineering change, the Engineering Director must be at the CCB meeting).

5.2 No more than two (2) Quorum members can be delegates in a given CCB meeting. If more than two (2) Quorum members are delegates, the CCB meeting should be rescheduled to a time when sufficient Quorum members can attend.

5.3 The initiating PM will be invited to attend to discuss the implications of change. This quorum represents the minimum breadth of expertise that must be present to represent the full range of stakeholder interests.

5.4 The P&C Change Administrator will summarize the conclusions for presentation to the CCB.

5.5 The P&C Change Administrator will maintain a list of actions arising from the CCB in the RMO Action Tool and provide follow-up reporting to the CCB.

5.6 All changes against projects utilizing NR or DO funding, and all work being executed in the NR or DO controlled window of work regardless of funding source, must be

assessed based on the change review and evaluation input and authority levels granted to the members of the CCB.

5.7 Prior to a change being presented at CCB to obtain funding to execute a change, the CCF should be thoroughly analyzed and reviewed by stakeholders.

5.8 CCB is not a forum to discuss scope acceptance, options to execute a scope or decide/obtain commitment on who is executing the work. These decisions should have been made prior to presenting the CCF for CCB review.

Note that the following categories of changes are not within the authority of the CCB:

1.) Use of any Schedule Contingency within the high confidence schedule (P90).

2.) Use of any Program Contingency, including F&IP/SIO Program or Project Contingency.

3.) All changes related to a change in OPG staffing/resources.

4.) Any change that the contingency authority or CCB deems to require higher levels of review at PCCB.

The CCB needs to assess these types of change requests and either reject the change or recommend the change for approval to the PCCB. Note that use of F&IP and SIO project contingency is subject to PCCB review only and not CCB review per the PCCB Terms of Reference.

6.0 OUTPUT

Approved Change Control Forms

7.0 CONSUMERS

PP&C Department, Directors (applicable)

8.0 ATTENDEES AND QUORUM:

Quorum Members:

- Director, Project Assurance & Contract Management
- Director, Refurbishment Engineering
- Director, Refurbishment Operations & Maintenance
- Director, Unit Outage, NR
- Director Project Planning & Controls (Sponsor)
- NR Finance Controller
- CCB Members must provide an authorized delegate for CCB Meetings to maintain quorum.

Non-quorum Members:

- Manager, PP&C, Cost and Change Management, Nuclear Projects (Chair)
- P&C Change Administrator
- Initiating Project Manager or Director
- Other subject matter experts may be invited by the Chair/PM for issue-specific input

Table 1: CCB Management Approvers by Change Category

Change Category	Change Category Description	CCB Reqd.	Approval Authority
1	**Project Contingency Changes; excluding F&IP and SIO Projects:**		
	1a.) Nuclear Refurbishment (NR):		
	1a1.) Any new scope or new DSRs	Yes	SVP, Nuclear Refurbishment
	1a2.) related to any Project EstimatingUncertainty or Project Discrete Risks greater than $5	Yes	SVP, Nuclear Refurbishment
	1b.) Unit Cyclic Outage (DO):		
	1b1.) Any new scope or new DSRs	Yes	SVP, Nuclear Refurbishment
	1b2.) related to any Project Estimating Uncertainty or Project Discrete Risks greater than $250k	Yes	SVP, Nuclear Refurbishment
2	**Schedule Changes:**		
	2a.) Up to 5 day impact on critical path in Working Schedule (P50).	Yes	SVP, Nuclear Refurbishment
	2b.) Greater than 5 day impact on critical path in Working Schedule (P50).	Yes	SVP Nuclear Projects
3	**Other Changes recommended for CCB Approval**		
	Any change that the change department, contingency approval authority or project manager/director deems to require higher levels of review at CCB.	Yes	SVP, Nuclear Refurbishment

9.0 MEETING FREQUENCY

The CCB will convene at a frequency dependant on the volume of changes received, and may be required to convene on an urgent basis if the evaluation of a change warrants. For urgent CCF's email communication of changes and voting buttons will be utilized with the P&C Change Administrator coordinating.

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Guideline

Internal Use Only	
Document Number: NK38-REF-09701-10007	Usage Classification: Information
Sheet Number: N/A	Revision: R000

Title:
TERMS OF REFERENCE FOR THE NUCLEAR REFURBISHMENT PROGRAM CHANGE CONTROL BOARD

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Terms Of Reference For The Nuclear Refurbishment Program Change Control Board

NK38-REF-09701-10007-R000
2017-12-21

Order Number: N/A
Other Reference Number:

Internal Use Only

Prepared By: Doug Salter
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Planning & Project Controls
Nuclear Project Management Office

Guideline	Internal Use Only		
	Document Number: NK38-REF-09701-10007		Usage Classification: Information
	Sheet Number: N/A	Revision Number: R000	Page: 2 of 5

Title:
TERMS OF REFERENCE FOR THE NUCLEAR REFURBISHMENT PROGRAM CHANGE CONTROL BOARD

Revision Summary

Revision Number	Date	Comments
R000	2017-12-21	Initial issue. Note: This document supersedes record NK38-CORR-09701-0635785

Guideline	Internal Use Only	
	Document Number: NK38-REF-09701-10007	Usage Classification: Information
	Sheet Number: N/A / Revision Number: R000	Page: 3 of 5

Title:
TERMS OF REFERENCE FOR THE NUCLEAR REFURBISHMENT PROGRAM CHANGE CONTROL BOARD

1.0 OBJECTIVE

In accordance with the Contingency Memorandum issued by Gary Rose and Dietmar Reiner dated September 23, 2016 this Nuclear Refurbishment Program Change Control Board (PCCB) is established for the purposes of reviewing and approving changes that exceeds the authority of the Nuclear Refurbishment Change Control Board (CCB) approval limits.

2.0 MEETING TIER

Tier 1 (top Tier) – Executive level where NPET must attend – NPET is the sponsor

Sponsor: VP, Project Planning & Control, Nuclear Projects (Sponsor and Chair)

Chair: VP, Project Planning & Control, Nuclear Projects (Sponsor and Chair)

3.0 SUPPLIER

Project Managers, Project Planning and Controls Leads, Vendor Input:

4.0 INPUT

Change Control Forms

5.0 PROCESS

A change is considered to be approved by the PCCB if:

(a) It is a low value change (<$250K) or it is an urgent change which cannot wait for a regularly scheduled PCCB Meeting and the PCCB chair in association with the Director of Controllership and Director of Planning and Controls has recommended the change be approved by proxy (no PCCB meeting required). However, all changes in this category will be presented for review at the next PCCB meeting.

(b) Voted to be approved by two Quorum members PLUS the PCCB Sponsor.

(c) No more than two (2) Quorum members can be delegates in a given PCCB meeting. If more than two (2) Quorum members are delegates, the PCCB meeting should be rescheduled to a time when sufficient Quorum members can attend.

The PCCB will convene at a frequency dependant on the volume of changes received, and may be required to convene on an urgent basis if the evaluation of a change warrants.
The CCF will be presented by the Project Director or Functional Budget owner requiring the funds. The meeting will be closed (Quorum and Non-Quorum members only) with the presenting Director or Functional Budget owner invited into the meeting to present their CCF.

The PCCB may make an immediate decision, or discuss privately and render a decision post presentation.

The Manager Cost & Change Management, PP&C, Nuclear Projects will summarize the conclusions for presentation to the PCCB. He/she will maintain a list of actions arising from the PCCB, ensure that all approved changes are promptly processed, and provide follow-up reporting to the PCCB.

Should a change be determined to impact multiple departments, business units or vendor partners, then the Chair of PCCB may recommend that the change be presented at the Change Management Pillar meeting to determine if a formal communication plan is required.

Below is a table outlining the executive approvers by change category:

Table 1: PCCB Executive Approvers by Change Category

Change Category	Change Category Description	PCCB Required	Approval Authority
1	**Schedule Changes:**		
	1a.) Up to 5 day impact on High Confidence Schedule (P90)	Yes	SVP Nuclear Projects
	1b.) Greater than 5 day impact on High Confidence Schedule (P90)	Yes	CNO/CEO
2	**Program Contingency Changes:**		
	2a.) related to Estimating Uncertainty	Yes	SVP Nuclear Refurbishment
	2b.) related to Discrete Program Risks	Yes	SVP Nuclear Projects
	2c.) related to Project Contingency shortfalls	Yes	SVP Nuclear Projects
3	**OPG Resource Changes:**		
	3a.) Staffing changes	Yes	SVP Nuclear Projects
4	**Other Changes recommended for PCCB Approval**		
	4a.) Contingency authority or CCB deems to require higher levels of review at PCCB	Yes	SVP Nuclear Projects
5	**Project Contingency Changes for F&IP and SIO Projects:**		
	5a.) All changes involving new Scope or new DSRs.	Yes	SVP Nuclear Projects
	5b.) All changes greater than $5 Million.	Yes	SVP Nuclear Projects
	5c) Project contingency draws exceeding the contingency drawdown limits as detailed in Reference 1 *E.g. Project contingency draw of $2M on estimate uncertainty for a project that has cumulatively drawn estimate contingency for over $4M already.*	Yes	SVP Nuclear Projects

6.0 OUTPUT

Upon review of a given change, the PCCB chair will convene a PCCB meeting or recommend the change to be “approved by proxy”. A Proxy PPCB approval will typically be applied in instances of low value changes (<$250K) or for changes of an urgent nature that cannot wait for a regularly scheduled PCCB Meeting. For “Approve by proxy” changes, PCCB chair, in association with the Director of Controllership and Director of Project Planning & Control, will recommend a change for approval electronically and request feedback from quorum members. If no objections received from PCCB quorum members within 2 business days, then the change is approved without a PCCB meeting.

For changes submitted to PCCB, where the approval authority is in the SVP-Nuclear Projects/CNO/CEO/CFO level, the changes must be recommended for approval at PCCB prior.

7.0 CONSUMERS

- Project Manager
- Project Planning and Control Lead
- Vendor

8.0 ATTENDEES AND QUORUM

Quorum Members:

- SVP Nuclear Refurbishment
- VP, Engineering, Nuclear Projects
- VP, Project Planning & Control, Nuclear Projects (Sponsor and Chair)
- VP, Projects Assurance and Contract Management
- Director Controllership

PCCB Members must provide an authorized delegate for PCCB Meetings to maintain quorum. Delegates must be direct reports of PCCB Quorum members. The PCCB Sponsor role cannot be delegated downward but may delegated upward to SVP, Nuclear Projects.

Non-quorum Members:

- Director, Nuclear Refurbishment, PP&C (Alternate Chair)
- Manager Cost & Change Management, PP&C, Nuclear Projects (Secretary/Administrator of all Decisions)
- Manager Project Management Office, Scheduling, PP&C, Nuclear Projects
- Manager, Project Controls- Human Resource Support

9.0 MEETING FREQUENCY

The PCCB will convene at a frequency dependant on the volume of changes received, and may be required to convene on an urgent bas

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Document Number: NK38-TOR-09701-00001		Usage Classification: N/A
Sheet Number: N/A	Revision Number: R003	Page: 1 of 11

Title:
DARLINGTON NUCLEAR REFURBISHMENT PROGRAM – REFURBISHMENT CHANGE CONTROL BOARD TERMS OF REFERENCE

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Darlington Nuclear Refurbishment Program – Refurbishment Change Control Board – Terms of Reference

NK38-TOR-09701-00001
2024-11-11

Order Number: N/A
Other Reference Number: N/A

Internal Use Only

Prepared by: jenny kahaleh 11-Nov-2024
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Approved by: Dec 2. 2024
Slawek Gora Date
Director Project Controls
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Guideline	Internal Use Only		
	Document Number: NK38-TOR-09701-00001		Usage Classification: Information
	Sheet Number: N/A	Revision Number: R003	Page: 2 of 12

Title:
DARLINGTON REFURBISHMENT PROGRAM – REFURBISHMENT CHANGE CONTROL BOARD

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Guideline

Internal Use Only		
Document Number: NK38-TOR-09701-00001		Usage Classification: Information
Sheet Number: N/A	Revision Number: R003	Page: 3 of 12

Title:

DARLINGTON REFURBISHMENT PROGRAM – REFURBISHMENT CHANGE CONTROL BOARD

Revision Summary

Revision Number	Date	Comments
R000	2021-06-22	Initial issue
R001	2024-03-25	General Update: - Section 3.0 Added core scope and non-core scope definitions - Section 4.0 Added RCCB Criteria for DRP Funded projects and non-DRP funded projects - Section 5.0 Added intent and non-intent changes definitions - Section 5.1: o Revised Supporting documents section o Added RCCB Timelines - Section 6.0 Revised Approval Limits - Appendix A Revised RCCB Flow chart - Appendix B Revised Acronyms
R002	2024-10-07	Section 6.3 added documentation requirements for changes outside of the SLT $45M approval limit
R003	2024-11-05	- Section 4.0 added RCCB criteria for one-to-one scope and budget transfers within DRP - Section 6.2 Added CPO Approval requirement - Appendix A: Flow chart revision

Guideline	Internal Use Only		
	Document Number: NK38-TOR-09701-00001		Usage Classification: Information
	Sheet Number: N/A	Revision Number: R003	Page: 4 of 12

Title:
DARLINGTON REFURBISHMENT PROGRAM – REFURBISHMENT CHANGE CONTROL BOARD

1.0 OBJECTIVE

The objective of the Refurbishment Change Control Board (RCCB) is to review and approve proposed:

(a) New scope additions and/or scope removals executed during the Darlington Refurbishment Program (DRP) outage window that could impact the approved DRP scope. Such changes may be funded within the DRP or outside of the DRP.

(b) Project changes in the Darlington Refurbishment Program (DRP) that exceed the authority of budget owners (Over $5M). Such changes may impact schedule, cost, and/or scope.

2.0 MEETING QUORUM, SPONSOR, CHAIR

The RCCB is a cross-functional decision panel with representations from various business units. All changes presented at the RCCB must be presented by the budget owner requesting the change or project sponsor requesting new scope. Delegates may be assigned to the budget owner or project sponsor's discretion.

2.1 Meeting Quorum and Voting Members:

The RCCB quorum consists of management representation from the organizations of Work Control, Engineering, Operations & Maintenance, Planning & Controls, Finance, Commercial/Contracts, and, where the change affects the station, management from Refurbishment/Station Integration. Empowered delegates may represent quorum members; however, all areas must be represented in each meeting.

2.2 Sponsor

Vice President, Planning & Controls, Nuclear Project Management Office

2.3 Chair

Director, Planning & Controls, Darlington Nuclear Refurbishment

2.4 Administrators

Senior Manager, Planning & Controls, Darlington Nuclear Refurbishment
Manager, Planning & Controls, Darlington Nuclear Refurbishment
Project Controls Officers, Darlington Nuclear Refurbishment

2.5 RCCB Meeting Frequency

The RCCB will meet weekly (on Wednesdays) when changes are to be reviewed and approved. If there are no agenda items, the meeting will be cancelled.

3.0 DEFINITIONS

The terminology related to scope are defined as follows:

Term	Definition
In-scope changes	a) Changes that affect existing scope that is funded within the latest-approved DRP budget. This includes (1) changes to existing scope and (2) removal of existing scope. OR b) Changes that have no scope impact but affect the DRP budget and are required to be presented to RCCB for approval based on the process shown in Appendix A.
Out-of-scope changes	Changes that result in the addition of scope[1] to the DRP. OR Station scope that needs to be executed during DRP. Scope may be funded within or outside of the DRP; similarly, it may be executed by the DRP or by the Station.
Core Scope[2]	Core Scope consists of work that must be done to achieve the Primary Objective of Refurbishment. Core scope will determine the critical path for the refurbishment outage and set the lower boundary for the cost estimate.
Non-Core Scope[2]	Consists of work that will be performed in the refurbishment period if it has no impact on the projects Core Scope critical path, does not add risk to the successful completion of core scope, and where cost or resource efficiencies and station priority warrant the work to be executed in the refurbishment period.
[1]Scope additions are defined as changes that meet any of the following criteria: a) Scope was not included in the basis of estimate of the latest approved DRP budget, including contingency; or b) Requires a change to the description of an approved Darlington Scope Request (DSR).	
[2] refer to D_PROC_INS_NK38-INS-09701-10001_006 Sec 3.2 for further details about Core and Non-Core Scope	

4.0 RCCB CRITERIA BASED ON PROJECT FUNDING SOURCE

To streamline the approval process for projects being executed in refurbishment windows, the following requirements apply depending on the project's type of funding:

DRP Funded Projects:

- DRP funded projects: Can perform a change to the execution strategy within their existing budget without need for RCCB approval, providing flexibility while staying within budget limits (less than $5M).
- Any DRP scope revision requires RCCB approval.
- DRP Only, for budget ownership transfers maintaining the same scope between projects/bundles under the same unit, approvals are required from both exchanging budget owners, followed by RCCB Chair approval only, with no CEO approval required, even if the transferred amount exceeds $60 million.

Non-DRP Funded Projects:

- Station Cyclical and OM&A funded projects: Approval from the DRP Scope Review Board (SRB) is required before presentation to the RCCB. However, if advised by the Outage Section Manager, certain requests that might have an impact on refurbishment must first be approved by the RCCB before obtaining SRB approval. Moreover, new Core Scope-related requests must adhere to NK38-INS-09701-10001 guidelines, requiring RCCB approval and will not be discussed through the SRB process. See Appendix D&E of NK38-INS-09701-10001 for the definition of Major Core Scope.
- AISC funded projects: Do not need SRB approval before presentation to the RCCB. However, DRP Work Management must agree on the scope and resource availability before presenting these projects to the RCCB.

  Please refer to Appendix A for further information regarding the RCCB process for DRP and Non-DRP funded projects.

5.0 PREPARING FOR RCCB

The party requesting the change is responsible for obtaining written approval from the budget owners (Per Organizational Authority Register Section 1.3) and gain endorsement and consensus from affected stakeholders prior to presentation at RCCB.

The presenting Team shall determine if the change being presented to RCCB is considered an In-Scope or an Out-of-Scope Change by referring to the definitions under Section 3.0.

Note:

- Non-Intent changes are related to schedule or cost adjustments of an administrative nature that do not impact project's scope and therefore, do not necessitate RCCB approval.
- Intent changes include changes to the scope, cost or schedule of DRP, or non-DRP scope changes that, although not directly impacting the refurbishment but must be executed during the Darlington Refurbishment outage.

5.1 RCCB Documentation

An executive summary for the change request along with the required supporting documents, must be submitted to the RCCB@opg.com mailbox 9 calendar days before the meeting (Monday one week before the RCCB Meeting held on Wednesday).

The RCCB Administrators will perform a readiness check of the submitted documentation and reserve the right to request revisions even if it delays the presentation date. The meeting package will be issued to quorum members 2 business days before the meeting (i.e., by 10 a.m. Mondays).

The executive summary shall clearly outline the proposed change, source of funding, and how it affects the DRP. The questions included in the template anticipate questions from RCCB and provide thorough answers to build a strong case for approval. This approach ensures that decision-makers understand the proposal and can make informed decisions to support it within the program.

Supporting Documents

a. Decision Record Analysis Summary (DRAS) or Decision Record (DR) - in the Decision module in ePMX.

   For scope additions, endorsement from the following parties is required to be documented in the DRAS/DR:

   - Design Authority, Darlington Refurbishment for technical merit confirmation.
   - Operations Manager, Darlington Refurbishment for concurrence
   - Finance Controller, Darlington Refurbishment for funding source confirmation.

b. New or modified Darlington Scope Request (DSR)

   If the change has a DRP scope impact (i.e., changing or removing an existing scope record), a new or a modified DSR is required, or scope injection written approval by the concerned Business Unit funding committee (e.g. AMOC, PMOC, etc.)

c. Change Control Form (CCF)

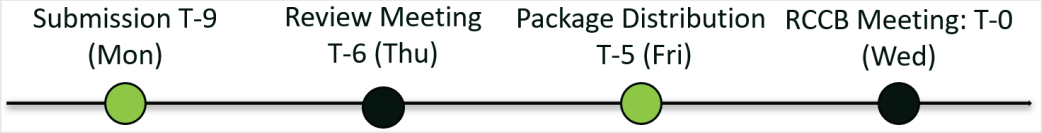
For DRP projects, a CCF must be submitted to the RCCB Administrators to complete the quality checks, and the Quality Checklist shall be fully signed by the reviewer and requesting party prior to the meeting. The CCF shall document the preferred option, including the impact to the DRP cost and schedule baselines, risk, resources, and commercial/contracts.

If minor changes are needed to the RCCB Package and/or the CCF content after the RCCB meeting, CCF updates can be made prior to routing the CCF for final approval post RCCB meeting. Additionally, changes to the RCCB Package can be made and documented as a revised package version, which can then be filed for final record-keeping purposes.

The RCCB administrators are responsible for issuing minutes of meeting to all meeting attendees and quorum members within 2 business days of the meeting. Voting decisions for each RCCB change form and any applicable actions (with owners) will be recorded in the meeting minutes and be documented in ePMX. Scope rejections must also include a documented rationale in ePMX.

A final copy of the RCCB-endorsed CCF and associated supporting documentation shall be provided to the budget owner(s) by the respective Planning & Controls Single Point of Contact (SPOC) for record-keeping purposes.

RCCB Timelines in days



6.0 APPROVAL LIMITS

6.1 Refurbishment Change Control Board (RCCB)

The RCCB can approve scope changes with the following criteria:

(a) Cost impact does not exceed $10 Million.
(b) No change to public commitments (i.e., high-confidence schedule dates).
(c) Critical path impact does not exceed 2 days.

A change that is tabled at RCCB for approval is considered approved when all quorum members vote to approve the change during the RCCB meeting. If a quorum member rejects the change, the chair of RCCB can escalate the change to the Senior Vice President (SVP) Darlington Projects for a final decision. At the discretion of the SVP of Nuclear Refurbishment, the change may also be presented and escalated to the Nuclear Refurbishment Senior Leadership Team for a final decision.

6.2 Escalation to Refurbishment Senior Leadership Team

Effective Aug 2024, if the requested change falls outside RCCB authority as described in Section 6.1, and is under the $60M OAR limit, the change must first gain RCCB approval and then final email approval from the Chief Projects Officer (CPO) and Senior Leadership Team (SLT) as per the following:

For changes up to $45 Million change value:

- Senior Vice President, Nuclear Refurbishment
- Vice President, Nuclear Refurbishment Execution
- Vice President, Business Development & Commercial Management
- Vice President, Enterprise Planning & Project Controls

For changes up to $60 Million change value, in addition to the above approvals:

- Chief Projects Officer, Enterprise Projects.

The requesting party must obtain SLT endorsement and consensus before submitting the final approval email.

6.3 Escalation Beyond Refurbishment Senior Leadership Team

Effective Aug 2024, if the requested change falls outside of the CPO and SLT $60M approval limit, the change will be considered approved via inclusion in Major Projects Committee Report to the Board of Directors (BOD) after obtaining RCCB, CPO and SLT concurrence on the change.

The approval will be formally documented and recorded in the Minutes of Meeting, which will be maintained as part of the item's documentation records.

6.4 Meeting Outcomes

There are four possible outcomes for items presented to the RCCB.

Outcome	Definition
Approved	Item is fully approved as is.
Conditionally Approved with Actions	Item is approved subject to the satisfactory completion of any and all associated actions. *Action closure notes must be provided to the RCCB Administrators prior to action closure within ePMX. RCCB Administrators reserve the right to bring the item back to RCCB for further discussion if required.*
Deferred	Item is not approved and is deferred as a bring-back to a later meeting upon addressing the actions laid out by quorum.
Rejected	Item is rejected and is not a bring-back to a later meeting.

7.0 DOCUMENTATION OF CHANGES POST-RCCB

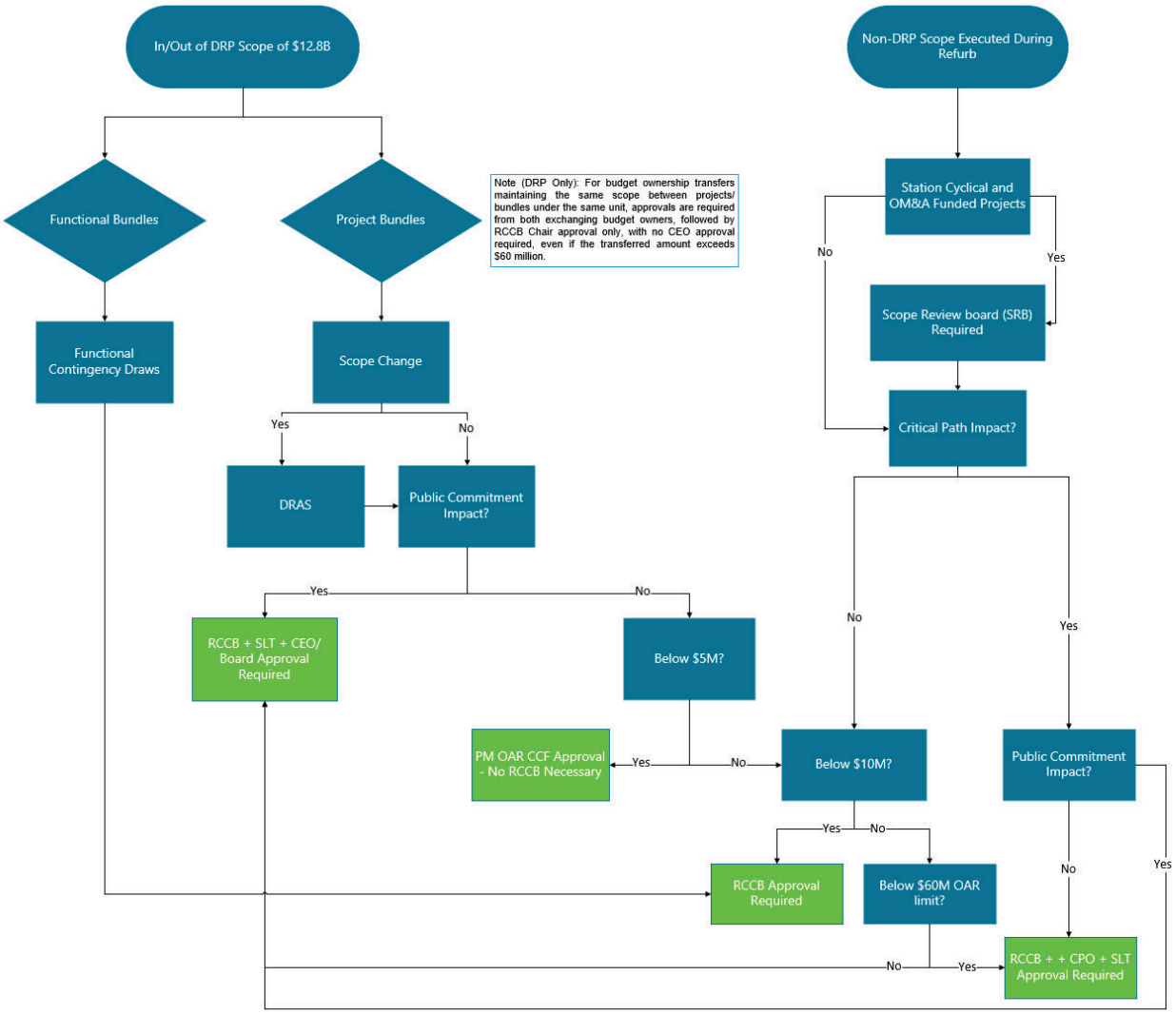
The RCCB administrators are responsible for issuing minutes of meeting to all meeting attendees and quorum members within 2 business days of the meeting.

The requesting party is responsible for updating all source systems pertaining to an approved change, including (but not limited to):

(a) DRAS documentation and status in ePMX;
(b) CCF documentation (RCCB minutes documenting approval and all associated supporting documents to be merged as one PDF and uploaded to SharePoint);
(c) Action management related to the approved change/decision in ePMX;
(d) Cost system (EcoSys);
(e) Scheduling system (P6);
(f) Risk register in ePMX and associated risk analysis and assessments;
(g) Work management systems and DSR database (If applicable);
(h) Purchase Order system (in AS9).

Appendix A: RCCB Process Flowchart

All changes must be evaluated on a holistic basis, i.e., including impact to functional resources.



**DRAS Criteria can be found in the ePMX Desktop Guide: OPG Home Business Functions Enterprise Project Management. The ePMX Desktop Guide is posted to this webpage.*

Appendix B: Acronyms

CCF	Change Control Form
PCO	Project & Controls Officer
DRAS	Decisions Record Analysis Summary
DRP	Darlington Refurbishment Program
DSR	Decision Scope Request
ePMX	Enterprise Project Management Extensions
GPF	Gate Progression Form
PD	Project Director
PM	Project Manager
RCCB	Refurbishment Change Control Board
SLT	Senior Leadership Team
SPOC	Single Point of Contact

Board Staff Interrogatory #009

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 3 / Chart 1
Ref 2: Exhibit A1 / Tab 2 / Schedule 2
Ref 3: EB-2020-0290, Decision and Order, November 15, 2021

Preamble:

At Reference 1, OPG presents the Nuclear Revenue Requirement Deficiency for the 2027 to 2031 period for OPG's nuclear facilities. Notes 3a to 8a provide references for the differences shown for each respective line and year in Chart 1.

In Reference 2, OPG outlines the approvals sought through this proceeding. Among these, this application seeks OEB approval of five distinct revenue requirements in each of 2027 to 2028 relating to OPG's nuclear facilities. This application also seeks five distinct revenue requirements in each of the same years relating to the Darlington New Nuclear Program (DNNP) facilities. Similarly, with Reference 3, by approving the Settlement Proposal, the OEB approved five distinct revenue requirements in each of 2022 to 2026 relating to OPG's nuclear facilities.

Also at Reference 2, the application seeks approval of a blended nuclear payment amount that reflects the combined nuclear revenue requirements relating to the OPG and the DNNP nuclear facilities.

Question(s):

a) Please reproduce Chart 1 with lines 4 through 9, the Changes in Revenue Requirement, on the basis of comparing the total cumulative five-year revenue requirement of EB-2020-0290 to the total cumulative five-year nuclear revenue requirement of EB-2025-0297. For the total cumulative nuclear revenue requirement for EB-2025-0297, please do so on the basis of the sum of OPG's nuclear facilities and the DNNP facilities.

b) Please further break-down the "Other" category so as to ensure that no individual driver of nuclear deficiency in part a) is smaller than "Other" on a five-year basis. In other words, please add additional categories and details as necessary so that "Other" is the smallest identified deficiency in the table.

c) Please update the accompanying narrative with respect to any new items arising from part b). For clarity, OEB staff is not requesting that the narrative for already identified items be updated in this interrogatory response.

d) Please also provide any additional information and explanation required to reconcile the EB-2020-0290 cumulative revenue requirement of $16,064.7 million and the proposed cumulative OPG nuclear and DNNP revenue requirement of $26,373.8 million.

Response

a) Ex. A1-3-3, Chart 1 has been reproduced in Attachment 1 on the basis of comparing the total cumulative five-year revenue requirement from EB-2020-0290 to the total cumulative five-year nuclear revenue requirement proposed in this Application, including the DNNP facilities.

b) Refer to Attachment 1.

c) The accompanying narrative with respect to new items at Attachment 1 relative to Ex. A1-3-3, Chart 1 are outlined as follows:

Darlington New Nuclear Project ("DNNP") (+26% of total change in Revenue Requirement) – Reflects DNNP Unit 1 entering rate base in 2030, on a forecast basis, the associated operational readiness and operating OM&A costs, and the recovery of interest amounts on capital expenditures for the DNNP under the concurrent cost recovery ("CCR") framework pursuant to Ontario Regulation 53/05 (Ex. I1-1-1).

Darlington Refurbishment Program ("DRP") (+13% of total change in Revenue Requirement) – Reflects the completion of the DRP and inclusion of all four refurbished units in rate base during the full IR term. Refer to Ex. D2-2-3 for further details.

Darlington Uranium Fuel costs (+6% of total change in Revenue Requirement) – Reflects higher forecast generation from Darlington with the completion of the DRP and higher nuclear fuel bundle costs since EB-2020-0290, which have been impacted by trends including the global demand for nuclear power and nuclear fuel, geopolitical landscape, and supply-demand uncertainty in the uranium market. Nuclear fuel costs are discussed in Ex. F2-5-1 and Ex. F2-5-2.

OM&A Settlement (+3% of total change in Revenue Requirement) – Reflects the EB-2020-0290 OM&A settlement adjustment of -3% on Nuclear Base, Outage, Project and Corporate Support OM&A costs and Asset Service Fees. Refer to EB-2020-0290 Payment Amounts Order, Appendix A, Table 7, Line 13.

Nuclear Asset Service Fees (+2% of total change in Revenue Requirement) – Reflects the impact of new corporate digital technology projects since EB-2020-0290 including Technology Modernization projects such as the planned Finance ERP solution and the Enterprise Asset Management Project, and the OPG Corporate Headquarters completed in 2025. This is partially offset by a recovery of Nuclear Isotopes Asset Usage Fees by the nuclear business. Refer to Ex. F3-2-1 and Ex. F3-2-2 for further details.

d) The change in cumulative revenue requirement of $10,202.3M as noted in Attachment 1, line 15 is the difference between the EB-2020-0290 cumulative nuclear revenue requirement of $16,100.9M (refer to the sum of 2022-2026 Revenue Requirement Net of Stretch Factor in EB-2020-0290 Payment Amounts Order, Appendix A, Table 8, line 4) and the sum of this Application's cumulative nuclear revenue requirement, inclusive of the DNNP facilities, proposed for the 2027-2031 period of $26,303.2M (refer to the sum of 2027-2031 Revenue Requirement Net of Stretch Factor in Ex. I1-1-1, Table 2, line 26 and sum of 2027-2031 Revenue Requirement in Ex. I1-1-1, Table 2a, line 22). No additional information is required.

Chart 1: Nuclear Deficiency for 2027-2031 Period Cumulative

Line No		($M) Cumulative	Reference
	Changes in Revenue Requirement:		
4	Pickering Refurbishment Program	3,878.1	Note 1a
5	Darlington New Nuclear Project (DNNP) LP Revenue Requirement	2,686.0	Note 2a
6	Pickering Ongoing Operations	(1,323.2)	Note 3a
7	Darlington Outage OM&A Expenses	167.8	Note 4a
8	Cost of Capital Parameters - OPG nuclear facilities	1,063.3	Note 5a
9	Darlington Projects	1,192.0	Note 6a
10	Darlington Refurbishment Program	1,339.9	Note 7a
11	Darlington Uranium Fuel Costs	592.6	Note 8a
12	OM&A Settlement	273.6	Note 9a
13	Nuclear ASF	170.8	Note 10a
14	Other	161.4	Note 11a
15	**Total Change in Revenue Requirement (lines 4 through 14)**	**10,202.3**	

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)	
1a	**Pickering Refurbishment Program (PRP)**	**PRP revenue requirement impact comprises the sum of:**		N/A	
		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)		
2a	**Darlington New Nuclear Project (DNNP)**	**DNNP revenue requirement:**		N/A	
		Revenue Requirement	Ex. I-1-1 Table 2a line 24, cols. (a) to (e)		
3a	**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, cols. (g) to (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 cols. (g) to (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, cols. (g) to (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)	Per OPG's internal support of EB 2020-0290 Ex. F4-4-1 Table 3 lines 3 and 5, cols. (g) to (k)
		Outage OM&A	Ex. F2-4-1 Table 1 line 6, cols. (h) to (l); plus Ex. F2-4-1 Table 1 line 10, cols. (h) to (l)	Outage OM&A	Ex. F-2-4-1 Table 1 line 6, cols. (g) to (k); plus Ex. F-2-4-1 Table 1 line 10, cols. (g) to (k)
		Project OM&A	Ex. F2-3-1 Table 1 line 2, cols. (h) to (l); plus Ex. F2-3-1 Table 1 Note 3b, cols. (h) to (l); plus Ex. F2-3-1 Table 1 Note 3e, cols. (h) to (l)	Project OM&A	Ex. F2-3-1 Table 1 line 2, cols. (g) to (k); plus Ex. F2-3-1 Table 1 Note 4 Pickering NGS (Infrastructure + Portfolio Projects (unallocated)), cols. (g) to (k)

		Fuel	Ex. F2-5-1 Table 1a line 2, cols. (h) to (l)	Fuel	Ex. F2-5-1 Table 1 line 2, cols. (g) to (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, cols. (g) to (k)
		Depreciation	Ex. F4-1-1 Table 2 line 5, cols. (h) to (l)	Depreciation	Ex. F4-1-1 Table 2 line 4 cols. (g) to (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 [(Sum of EB 2020-0290 Ex. C1-1-1 Tables 1-5 line 4 col. (d)) divided by Sum of EB 2020-0290 Ex. C1-1-1 Tables 1-5 line 4 col. (a)] 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)]	Cost of Capital	Ex. B3-1-1 Table 2 line 4, cols. (c), (f) and (i) and line 12 cols. (c), and (f); Multiplied by: [EB-2020-0290 Ex. C1-1-1 Table 1 line 4 col. (b)] multiplied by [(Sum of EB 2020-0290 Ex. C1-1-1 Tables 1-5 line 4 col. (d)) divided by Sum of EB 2020-0290 Ex. C1-1-1 Tables 1-5 line 4 col. (a)] Plus: B3-1-1 Table 2 line 4, cols. (c), (f) and (i) and line 12 cols. (c), and (f); 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)]
4a	**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. F2-4-1 Table 1 line 3, cols. (g) to (k)
5a	**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: [(Sum of EB 2020-0290 Ex. C1-1-1 Tables 2-6 line 6 col. (d)) divided by Sum of EB 2020-0290 Ex. C1-1-1 Tables 2-6 line 6 col. (a)]		
6a	**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 [(Sum of EB 2020-0290 Ex. C1-1-1 Tables 1-5 line 4 col. (d)) divided by Sum of EB 2020-0290 Ex. C1-1-1 Tables 1-5 line 4 col. (a)] 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 1, cols. (c), (f) and (i) and line 9 col. (c) and (f) Multiplied by: Ex. C1-1-1 Table 1 line 4 col. (b) multiplied by [(Sum of EB 2020-0290 Ex. C1-1-1 Tables 1-5 line 4 col. (d)) divided by Sum of EB 2020-0290 Ex. C1-1-1 Tables 1-5 line 4 col. (a)] Plus: Ex. B3-1-1 Table 2 line 1, cols. (c), (f) and (i) and line 9 col. (c) and (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 F4-1-1 Table 2 line 1, cols.(g) to (k)
7a	**Darlington Refurbishment**	**DRP revenue requirement impact comprises the sum of:**		**DRP revenue requirement impact comprises the sum of:**	
		OM&A Expenses	Ex. F2-1-1 Table 1a, line 6, cols. (h) to (l)	OM&A Expenses	Ex. F2-1-1 Table 1a, line 5, cols. (h) to (l)

	Program (DRP)	Cost of Capital	Ex. B3-1-1 Table 2, lines 2 line 3, cols. (f) and (i) and lines 14 and 15 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, lines 2 and 3, cols. (f) and (i) and lines 14 and 15 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, lines 2 line 3, cols. (c), (f) and (i) and lines 10 and 11 cols. (c) and (f); Multiplied by: EB-2020-0290 Ex. C1-1-1 Table 1 line 4 col. (b) multiplied by col. (c); Plus: Ex. B3-1-1 Table 2, lines 2 line 3, cols. (c), (f) and (i) and lines 10 and 11 cols. (c) and (f); 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)
		Depreciation	Ex F4-1-1 Table 2 lines 2 and 3, cols. (g) to (k)	Depreciation	Ex F4-1-1 Table 2 lines 2 and 3, cols.(g) to (k)
8a	**Darlington Uranium Fuel Costs**	**Darlington Uranium Fuel costs revenue requirement:**		**Darlington Uranium Fuel costs revenue requirement:**	
		Fuel costs	Ex. F-2-5-1 Table 1, line 1, cols. (h) to (l)	Fuel costs	Ex. F-2-5-1 Table 1, line 1, cols. (g) to (k)
9a	**OM&A Settlement**	N/A - refer to EB-2020-0290		OM&A Settlement	Refer to EB-2020-0290 Payment Amounts Order, Appendix A, Table 7, Line 13 for the settlement adjustment.
10a	**Nuclear ASF**	**Nuclear ASF revenue requirement:**		**Nuclear ASF revenue requirement:**	
		Asset Service Fees	F-2-1-1 Table 1, line 14, cols. (h) to (l)	Asset Service Fees	F-2-1-1 Table 1, Line 9, cols. (g) to (k)
11a	**Other**	**Other revenue requirement impact is calculated as Total Revenue Requirement:**		**Other revenue requirement impact is calculated as Total Revenue Requirement:**	
		Less: Revenue Requirement Change Factors Identified	As calculated in Notes 3a to 10a	Less: Revenue Requirement Change Factors Identified	As calculated in Notes 3a to 10a

Board Staff Interrogatory #011

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 p. 41

Preamble:

At Reference 1, OPG states it plans to issue annual public reports on both the Pickering Refurbishment Program (PRP) and the Darlington New Nuclear Program (DNNP) status.

Question(s):

a) Please confirm OPG will publish a final annual report on the status of Darlington Refurbishment Program (DRP) in June 2026.

Response

a) Not confirmed. As described in Ex. D2-2-2, p. 13, line 7: “The report for 2025 will be filed with the OEB by December 2025, followed by what OPG expects to be the final report, for 2026, by December 2026.”

Board Staff Interrogatory #012

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 4 / Schedule 1 / Attachment 4, pp. 16-17

Preamble:

Reference 1 summarizes the "Darlington Outage Management" audit, which has a Generally Effective (White) rating.

Question(s):

a) Please identify the outages that were the subject of this audit.

b) Please provide the identified Memorandum of Understanding that "will be prepared between Darlington Operations and DNR organizations, describing the process for transferring deferred WOs." If it does not exist, please explain how the management action is "closed" without the memorandum being available.

Response

a) The following Darlington outages were the subject of the audit report: Unit 3 and Unit 4 in 2019, Unit 1 in 2020, and Unit 4 in 2021.

b) See Attachment 1.

ONTARIO POWER GENERATION

DARLINGTON REFURBISHMENT
Repowering Ontario

Memorandum of Understanding
Between
Darlington Nuclear Refurbishment (DNRU1/4)
And
Darlington Nuclear Generating Station Outage Department

RE: The process by which Work Orders de-scoped from Outage on Unit 1 and 4 will be brought to the DNRU Scope Review Board for consideration as potential scope addition to Refurbishment.

Whereas:

Any Work Orders de-scoped from planned or forced outages will be processed in the below manner.

DNRU3/1/4 and Darlington Work Management therefore agrees to the following:

- When a Work Order (W/O) is flagged for removal from Outage scope Darliington Outage Work Control Section Manager will contact the appropriate Refurbishment Work Control Section Manager (S/M).
- The W/O and reasoning for removal from Station scope will be communicated to Refurbishment S/M and the On-Line Scope Addition Request (N-FORM-10312) will be completed and sent to required parties for inclusion in the next scheduled DNRU Scope Review Board.
- Refurbishment Work Control will respond in a reasonable time frame as agreed upon by both parties (2 weeks) when the request is submitted as to whether or not the W/O will be accepted into Refurbishment scope.
- This MOU will be in effect until breaker open on DNRU4.

The following parties have reviewed and hereto executed this MOU:

Name	Company	Position	Date
Prepared by: Martin Wrobel	OPG	DNRU WCTL	April 20, 2022
Accepted by: Tony Carito	OPG	DNRU1/4 Outage Manager	April 26, 2022

Board Staff Interrogatory #013

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 4 / Schedule 1 / Attachment 4, pp. 22-23

Preamble:

Reference 1 summarizes the "Shared Services Re-imagine 1.0" audit, which has a Not Effective (Red) rating.

Question(s):

a) Please identify the projects or aspects from this Shared Services Re-imagine 1.0 that "are no-longer in use."

b) Please confirm whether "Shared Services Re-imagine 1.0" was included in any EB-2020-0290 revenue requirements. If confirmed, please estimate those amounts.

c) Please confirm whether "Shared Services Re-imagine 1.0" was included in any EB-2025-0297 revenue requirements. If confirmed, please estimate those amounts. Please explain the amounts in the 2027-2031 period.

d) Please provide the post-implementation review.

Response

a) The Shared Services Re-Imagine 1.0 audit identified four robotic process automations ("RPA") no longer in use at the time of the audit. Since the audit, all four RPAs are currently in use either as originally intended or through an alternate platform.

b) The EB-2020-0290 Asset Service Fee ("ASF") included $17.5M of capital in-service in the year 2020 for Re-Imagine 1.0. The total Nuclear ASF included in the approved nuclear revenue requirements over the 2022-2026 period is shown in the chart below:

Chart 1 – Nuclear Asset Service Fees, Re-Imagine 1.0

Amounts in $M					
Year	**2022**	**2023**	**2024**	**2025**	**2026**
Re-Imagine 1.0 ASF	$3.8	$3.5	$3.3	$1.5	Nil

*Reflects EB2020-0290 OEB approved capital structure and cost of capital parameters; excludes other OEB approved settlement adjustments

c) There are no amounts for Re-Imagine 1.0 included in the EB-2025-0297 proposed revenue requirements as the project was fully depreciated before 2027.

d) Refer to Attachment 1 for the Post-implementation Review.

ONTARIO POWER GENERATION	Document Number: FIN-TMP-PA-002*	Revision: R02	Page: 1 of 3
	POST IMPLEMENTATION REVIEW TEMPLATE (For Simplified PIRs only)		

Station:	Project Name: Re-Imagine	Project No.: ICIFI056/84397	Units:	Controlled Doc No.:

Approval	Cost	Date
Original Approval Estimate	$15M	Mar 13, 2019
Approval Revision Estimate	$2.5M	Jul 14, 2020
Final Approval Estimate	$17.5M	Jul 14, 2020
Final Actual Project Cost	$17,489K	Nov 11, 2020

Timing	
Target Date	Dec 31, 2019
Latest Approved i/s Date	June 30, 2020
In Service Date	June 30, 2020
Period used to calculate Performance result	2019-2020

DELIVERABLES	
Target	**Achievement**
FTE Reduction - OPS Controllership: 11	Re-Imagine developed automated forms for Business Planning to streamline the business process and gain efficiencies. The launch of the MyBusiness initiative enabled access to instantaneous Business Data through PowerBI dashboards and reports. This allows the business to focus on making better informed decisions based on current data. The foundation implemented by the Re-Imagine program will enable future additional FTE saving opportunities. FTE savings of 4.5 were realized by end of 2020.
FTE Reduction - Shared Services: 23 (RTH savings are yet to be realized and the work was foundational for future activations)	Re-Imagine facilitated the launch of the MyRequest portal. MyRequest is the enablement of self-serve capabilities for the entire organization and provides the framework for future self-serve opportunities. With the enablement of MyRequest, process changes in Accounts Payable have been realized. The digitization of 28 HR forms, coupled with workflow enablement where necessary, have eased manual effort within the Shared Services organization. The foundational work completed by the Re-Imagine program contributed to the 17 FTE savings by end of 2020.
FTE Reduction – BP & Reporting: 3	With the Re-Imagine program, optimization of the Business Unit Summary (BUS) application was completed which provided the business with time savings, reduced support costs for the application and provided the line with immediate access to see key data to make business decisions. FTE savings of 3 were realized by end of 2020.
FTE Reduction - External Reporting: 2	Re-Imagine enabled the automation of business processes for Financial Statement Consolidation. The Re-Imagine program laid the foundation for future utilization within the organization. Due to competing business priorities during the Re-Imagine rollout, FTE savings were unable to be realized by the end of 2020.
FTE Reduction - Supply Chain: 16	Under the Re-Imagine program, the Supply Chain organization was able to unlock Ariba functionality and implement the Ariba Contracts module, Supplier Lifecycle Performance and Guided Buying functionality. The enablement of these Ariba modules laid the foundation for future Ariba functionality. Under a subsequent project to the Re-Imagine program, Service Procurement in Ariba was implemented which will further contribute to the already realized FTE savings of 16 under the Re-Imagine program.

QUALITATIVE RESULTS	
Improvement of Manual Activities through MyRequest	Excessive manual business activities resulting from obtaining business information from multiple systems and the associated inter-system communication challenges were reduced with the implementation of MyRequest. Heavy reliance on email and paper communication coupled with a lack of fully formalized processes leading to traceability issues were significantly reduced with the implementation of digitized forms and workflow automation. Reducing the level of manual activities improved the quality, timeliness and accuracy of work.
Improved Reporting and Analytics through implementation of MyBusiness	The reporting and analytics functionality provided through MyBusiness has improved the productivity of the overall organization. MyBusiness has standardized, and improved access to, reporting and also reduced potential duplication of effort across business units. The business can now better focus on improved decision making vs data analysis. Although it is inherently very difficult to quantify these organization improvements in FTE terms, there has been widespread recognition of the MyBusiness benefits through received feedback and usage statistics.
Foundational platform for Future Opportunities	Although the Re-Imagine program did not fully realize all of the proposed FTE savings, the program enabled and simplified the implementation of future savings opportunities. In laying the platform with solutions such as MyRequest, MyBusiness, electronic forms, Forecasting Automation, Ariba Contracts, Ariba Guided Buying, additional FTE savings opportunities are expected to be more easily realized through subsequent initiatives such as Re-Imagine 2.0 and Service Procurement in Ariba.

KEY LESSONS	
Lesson Learned Review	• A lessons learned session was undertaken as part of project close-out. • Cross-functional alignment, planning/process review at the outset of the project, fixed price contracts and cohesive collaboration across a number of vendors was identified as some of the areas that worked well on the project. • Improvements in setting realistic timelines and factoring in re-work, utilizing dedicated internal OPG resources instead of vendor resources where more efficient and establishing centres of expertise to identify future process improvement opportunities were some areas of potential improvement for the project.
Other observations	• Some of the timing of FTE decreases in the identified groups has a longer lead time than originally anticipated when developing the business case metrics, due to timing of attrition/turnover and business factors including incremental new work (e.g. higher volume of calls to HRSC) and outcomes of labour negotiations and settlements. As a result, FTE savings have been slower to materialize than originally anticipated. • The financial evaluation was updated to reflect realized FTE savings and continues to be positive and supportive of the project.
FOLLOW-UP ACTIONS	

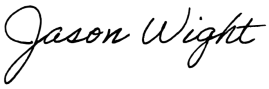
Prepared by: Carol Coe — Author — Date: February 8, 2021

Reviewed by: See below — Project Sponsor — Date: _____

Approved by: See below — Project Approval Authority Finance — Date: _____

Approved by: See below — Project Approval Authority — Date: _____

TITLE Post Implementation Review Procedure	Document Type: Procedure	Page: 3 of 3

Approvals	Signatures	Date
Recommended by: Project Sponsor Alex Kogan VP, Chief Controller		Sept 17, 2021
Recommended by: Project Sponsor Sarah Hough VP, Shared Services		
Recommended by: Project Sponsor Rob De Bartolo Acting VP, Supply Chain		
I concur with the business approval in this PIR.		
Finance Approval: Anthony Melaragno Director, Business Planning & Reporting		Sept 17, 2021
I concur with the business approval in this PIR.		
Approved By: Jason Wight Chief Information Officer		Oct 12, 2021

***ATTACH BCS*

BCS contains sensitive information and can be provided upon request.

Board Staff Interrogatory #015

Interrogatory

Reference:
Find references from this page: Governance & regulation | OEB applications – OPG
Ref 1: Exhibit A1 / Tab 4 / Schedule 1 / Attachment 4, pp. 71-72
Ref 2: Exhibit D1 / Tab 1 / Schedule 2 / Table 1
Ref 3: Exhibit D2 / Tab 1 / Schedule 3 / Tables 1a, 1b, and 1c
Ref 4: Exhibit D1 / Tab 1 / Schedule 2 / Tables 2a, 2b, and 3
Ref 5: Exhibit D2 / Tab 1 / Schedule 3 / Tables 2a to 2g, and 3

Preamble:

Reference 1 summarizes the "Long Lead Material Procurement & Supplier Capacity Risk Mitigation" audit, which has a Needs Improvement (Yellow) rating.

References 2 and 3 list the projects with budgets, for hydroelectric and nuclear, respectively, greater than or equal to $30 million.

References 4 and 5 list the projects with budgets or cumulative amounts as the case may be, for hydroelectric and nuclear, respectively, relating to projects with budgets less than $30 million.

Question(s):

a) For the hydroelectric projects listed in Reference 2, please identify all the projects that are reliant on long-lead materials.

b) For the nuclear projects listed in Reference 3, please identify all the projects that are reliant on long-lead materials.

c) For the hydroelectric projects that are collectively the projects relating to Reference 4, please estimate the proportion of the total budgets in each of 2027 to 2031 that relate to projects with long-lead materials.

d) For the nuclear projects that are collectively the projects relating to Reference 5, please estimate the proportion of the total budgets in each of 2027 to 2031 that relate to projects with long-lead materials.

e) Please generally explain how the findings of this audit relate to the hydroelectric projects with expenditures in 2027 to 2031 and explain how the findings are being addressed for these projects.

f) Please generally explain how the findings of this audit relate to the nuclear projects with expenditures in 2027 to 2031 and explain how the findings are being addressed for these projects.

Response

a) The following projects from Reference 2 are reliant on long-lead materials.

Chart 1 – Tier 1 (Total Project Cost >$30M) Regulated Hydroelectric Projects with Long-Lead Materials

Region	Facility	Project Name	Project Number
Niagara	Sir Adam Beck 1	BK1 G1/G2 Replacement	84185
Niagara	Sir Adam Beck 1	Sir Adam Beck 1 GS - Unit G5 Upgrade	82777
Eastern	Abitibi Canyon	Abitibi - G2 Capital Upgrades/HG	83155
Eastern	R.H. Saunders	SAU - G9 Capital Refurbishment	83495
Eastern	Chenaux	CHE - Limerick Isl. Spr Structure Sluice Gate Hoist	84494
Eastern	Coniston/Stinson	Coniston/Stinson GS Redevelopment	82087
Western	Kakabeka Falls	Kakabeka Falls GS Redevelopment	86386
Niagara	Sir Adam Beck 2	BK2 G20/G19 Refurbishment	87768
Eastern	Matabitchuan	Matabitchuan GS Redevelopment	86387
Eastern	R.H. Saunders	SAU - G12 Capital Refurbishment	86587
Eastern	Otter Rapids	Otter G1 Capital Upgrade	82542
Eastern	Abitibi Canyon	ABI - G1 Capital Upgrades	83148
Western	Alexander	G1 Capital Refurb	82391
Western	Alexander	G2 Capital Refurb	86792
Western	Alexander	G3 Capital Refurb	86793
Niagara	Sir Adam Beck 1	SAB1 Station Service Upgrade	86364
Niagara	Sir Adam Beck 1	BK1 G6 G8 Refurbishment	86372
Niagara	Sir Adam Beck 1	BK1 G4 Refurbishment	86570
Niagara	Sir Adam Beck 2	BK2 G18 G17 Refurbishment	87356
Niagara	Sir Adam Beck 2	BK2 G14 G13 Refurbishment	87357
Eastern	R.H. Saunders	SAU - G16 Capital Refurbishment	86937
Niagara	Sir Adam Beck 2	BK2 230kV Conductor Replacement	87362

b) The following are Tier 1 (Total Project Cost >$30M) Nuclear Operations projects from Reference 3 that are reliant on long-lead materials.

Chart 2 – Tier 1 (Total Project Cost >$30M) Nuclear Operations Projects with Long-Lead Materials

Facility	Project Name	Project Number
DN	DN Class II Uninterruptible Power Supply Replacement	31412
DN	DN Powerhouse Water Air Conditioning Units Replacement	31532
DN	DN Water Treatment Plant Interconnections	31535
DN	DN Radiation Detection Equipment Obsolescence	31544
DN	DN Air Conditioning Unit Replacement For Secondary Control Area	33621
DN	DN Major Pump-Sets Vibration Monitoring System Upgrades	33819
DN	DN – Standby Generator Controls Replacement	33973
DN	DN OH180 Aging Management Hardware Installation	80022
DN	DN R22 Refrigerant Air Conditioning Unit Replacement	80036
DN	DN Digital Control Common Process and Sequence of Events Monitoring Computer Aging Management	80078
DN	DN Main Power Output Protection System Replacement	80122
DN	DN Group II Pressure Transmitter Replacement	80123
DN	DN Obsolete Controller Replacement	80124
DN	DN Emergency Power Generator 1 And 2 Replacement	80126
DN	DN Fuel Handling Computer Input/Output Subsystem Interprocessor Communication Replacement	80148
DN	DN Fire Resistant Fluid Pump Improvement	80150
SEC	Security Project B	82929
DN	DN Fuel Handling Head Major Component Replacement	82947
IRI	DN Rapid Delivery Machine	83039
DN	DN Main Output Transformer & Unit Service Transformer Replacement	83296
DN	DN Large Moderator Temperature Control Valve Replacement	83297
DN	DN Secondary System Obsolete Control Valve Replacement	83298
DN	DN 4KV Motor Refurbishment And Replacement	83480
DN	DN Isolated Phase Bus Refurbishment	83484
DN	DN Powerhouse Upper Level Service Water Piping Replacement	83530
DN	DN Unit 2 Turbine Control and Auxiliary System Upgrade	83664
DN	DN Primary Heat Transport Liquid Relief Valve Modifications (Waterhammer)	84235
DN	DN Motor Operated Valves Replacements	84551
DN	DN Revenue Metering Transformer Replacement	84939

Facility	Project Name	Project Number
DN	DN Shutdown Cooling Heat Exchanger Replacement	31710
DN	DN Auxiliary Heating System	34000
DN	DN Zebra Mussels Mitigation & Improvements	38948
DN	DN RS Primary Heat Transport Pump Motor Replacement & Overhaul	73566 80144
DN	DN Public Address System Upgrade	31708
DN	DN Breathing, Instrument and Service Air Compressor Replacement	83933
DN	DN Powerhouse Elevator Replacement	84135
DN	DN Powerhouse Cranes Refurbishment	84139
DN	DN Vacuum Building Outage Power Operated Valves Replacement	84552
DN	Tritium Removal Facility Major Component Replacement Program	84764
DN	DN Low Pressure Service Water Strainer Backwash Motorized Valves Replacement	86280
DN	Darlington Steam Generator Moisture Separator Replacement	86693
DN	DN Motor Operated Valve Replacement Innage	86795
DN	U23 Darlington Steam Generator Moisture Separator Replacement	87151
DN	DN Tritium Removal Facility Cryogenic Refrigeration System Turbine Replacement	87191
DN	DN Turbine Rotor Replacement & Capital Spare	87807 87811
DN	DN Unit 1 and 2 Generator Stator Rewind	89281
DN	DN Steam Generator Soft Chemical Clean	89462
PN	PN 058 Boiler Room and Turbine Hall Crane Upgrade	89535
PN	PN 058 Turbine Auxiliary Building, Reactor Auxiliary Building Hoist and Cranes	89536
PN	P58 Second Simulator & Pickering Learning Centre Extension	89581

c) Chart 3 illustrates the proportion of annual budgets allocated to Tier 2 Projects from Reference 5.

Chart 3 – Proportion of Tier 2 (Total Project Cost $10-30M) Regulated Hydroelectric Projects with Long-Lead Materials

	2027	2028	2029	2030	2031
Proportion of the total Tier 2 budgets that relate to regulated hydroelectric projects with long-lead materials	57%	46%	22%	69%	0%

OPG is unable to provide the requested information for the Tier 3 (Total Project Cost <$10M) projects shown in Reference 4 as this requires an assessment of more than 600 projects, which cannot be undertaken within the timelines for responding to interrogatories.

d) Chart 4 illustrates the proportion of annual budgets allocated to Tier 2 Projects from Reference 5.

Chart 4 – Proportion of Tier 2 (Total Project Cost $10-30M) Nuclear Operations Projects with Long-Lead Materials

	2027	2028	2029	2030	2031
Proportion of the total Tier 2 budgets that relate to Nuclear Operations projects with long-lead materials	85.6%	91.3%	93.4%	99.5%	100.0%

OPG is unable to provide the requested information for the Tier 3 (Total Project Cost <$10M) projects shown in Reference 5 as this requires an assessment of more than 100 projects, which cannot be undertaken within the timelines for responding to interrogatories.

e) and f)

The audit findings were not based on (or related to) any specific nuclear or regulated hydroelectric project or projects; rather, the audit identified areas to improve the governance, documentation, and responsibilities in existing long-lead procurement and supplier capacity risk mitigation programs.

The audit findings are being addressed at the enterprise level by revising governance to ensure earlier and more consistent alignment with key stakeholders, and by ensuring long-lead material procurement and supplier capacity risks and mitigation actions are updated and reviewed at an appropriate frequency.

Board Staff Interrogatory #269

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / pp. 9, 20-21
Ref 2: Exhibit I1 / Tab 2 / Schedule 1 / Table 1
Ref 3: Exhibit I1 / Tab 2 / Schedule 1 / Table 2

Preamble:

At Reference 1, OPG explains the Gross Revenue Charge (GRC) Factor as a custom factor that removes the (I-X) escalation of the GRC amounts embedded in payment amounts. OPG states that this reflects the fact that the GRC expense is payable using a prescribed, non-escalating formula pursuant to the Electricity Act, 1998 and the related regulations. OPG also states that the proposal is to set the GRC Factor for the rate term at the fixed percentage amounts determined in this proceeding.

Reference 2 is the table where OPG provides illustrative payment amounts for 2028 to 2031 on the basis of the proposed Capital and GRC Factors and a forecast Inflation Factor of 3.49%. Reference 3 is the table where OPG presents the calculation of the Capital and GRC Factors for 2028-2031. The Capital Factor is calculated in the main table and the GRC Factor is calculated in the table included as Note 3.

Question(s):

a) Please identify and describe all alternative options that OPG considered for removing the I-X escalation of the GRC amounts embedded in payment amounts.

b) Please identify and explain the criteria used to select the proposed GRC Factor from the options considered. Please explain how the proposal is superior to the alternatives from part a).

c) If not identified in the response to part a), please explain why OPG did not consider excluding the GRC expense from the annual escalation to add back $352.2 million in revenue requirement to then determine the next year's hydroelectric payment amount.

d) Please explain why OPG's proposal does not afford equal treatment to other similar types of charges or taxes, such as Property Tax.

e) Please confirm that, with a constant production forecast over the entire IR term, the formulaic escalation of a payment amount is mathematically equivalent to formulaic escalation of revenue requirement after dividing by production.

For example, the following equation, showing the calculation of Reference 2 line 11, column (b):

$$51.39\ \left[\frac{\$}{MWh}\right] \times (1 + 6.96\%) = 54.97\ [\frac{\$}{MWh}]$$

Is mathematically equivalent to:

$$\frac{1{,}668.34\ [\$M]}{32.46\ [TWh]} \times (1 + 6.96\%) = \frac{1{,}784.46\ [\$M]}{32.46\ [TWh]} = 54.97\ [\frac{\$}{MWh}]$$

If not confirmed, please explain.

f) Please confirm that, if GRC expense were excluded from the annual escalation to hydroelectric payment amounts, the Capital Factor would have to be based on the Revenue Requirement amount that excludes the GRC expense. Further, if the GRC expense were excluded, all else being equal, the 2028 Capital Factor would be approximately 5.5%. If not confirmed, please explain, including a revised version of Reference 3 reflecting a Capital Factor derivation where the GRC expense is excluded from the annual escalation.

Response

a) and b)

OPG did not consider alternative options for removing the (I-X) escalation of GRC amounts embedded in payment amounts and no specific criteria were used to select the proposed GRCF. For the reasons set out at Ex. A1-3-2, Section 2.3.4, OPG believes that the inclusion of 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 regulated hydroelectric investments required in the IR term.

c) OPG did not consider excluding the GRC expense from the annual escalation and adding back $352.2M in revenue requirement to determine the next year's regulated hydroelectric payment amount.

OPG's proposed methodology for setting regulated hydroelectric payment amounts is a continuation of the price-cap index framework used to set such payment amounts during the 2017-2021 period, with the addition of a C-factor and the GRCF.

OPG interprets the requirements of adopting such an approach to be as follows, in terms of calculating regulated hydroelectric payment amounts for 2028-2031:

1) Remove GRC expense from the 2027 regulated hydroelectric revenue requirement
2) Determine a 2027 regulated hydroelectric payment amount value absent GRC expense
3) Determine a C-factor absent GRC expense
4) Escalate the regulated hydroelectric payment amount value absent GRC expense
5) Determine a GRC expense per MWh amount based on the 2027 test year
6) Add the GRC expense per MWh amount (step 5) to the escalated payment amount value absent GRC expense (step 4).

OPG observes that the result of the above process would be equivalent to updating the GRCF on an annual basis for the OEB inflation factor for such year, rather than establishing the GRCF percentages on a final basis. This topic is discussed in Ex. L-A1-CCC-003.

d) In the context of the proposed Custom IR framework, both the magnitude and non-escalating nature of the GRC expenses sets them apart from other costs included in the regulated hydroelectric revenue requirement. Property tax is immaterial in comparison to GRC costs and, unlike GRC, is subject to escalation (Ex. F4-2-1, p. 22, lines 20-24). For context, the 2027 property tax amount included in regulated hydroelectric revenue requirement is $2.1M, in comparison to the 2027 GRC costs of $352.2M.

e) Confirmed.

f) OPG confirms that the suggested approach in the question is mathematically correct, provided that the resulting hypothetical C-factor of 5.5% is applied to a regulated hydroelectric payment amount value that excludes GRC costs.

As discussed in the response to part c), determining a regulated hydroelectric payment amount with and without GRC costs is a complication of such an approach that otherwise has the same result as updating the GRCF on an annual basis for the OEB inflation factor for such year within the rate-setting framework proposed by OPG in this Application.

Board Staff Interrogatory #270

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / pp. 9, 20-21
Ref 2: Exhibit H1 / Tab 1 / Schedule 1 / pp. 29-30
Ref 3: Exhibit F1 / Tab 4 / Schedule 1 / pp. 4-6

Preamble:

At Reference 1, OPG explains the Gross Revenue Charge (GRC) Factor as a custom factor that removes the (I-X) escalation of the GRC amounts embedded in payment amounts. OPG states that this reflects the fact that the GRC expense is payable using a prescribed, non-escalating formula pursuant to the Electricity Act, 1998 and the related regulations. OPG also states that the proposal is to set the GRC Factor for the rate term at fixed percentage amounts determined in this proceeding. It appears the purpose of the GRC Factor is to hold the $352.2 million GRC Expense for 2027 constant through the IR term.

Reference 2 describes the proposed changes to the existing Gross Revenue Charge Variance Account (GRC VA). The proposal has two ways to expand the scope:

1. For deductions that may be approved under O. Reg 124/02
2. That the account also capture the revenue requirement impact of any differences in GRC expenses that result from a legislative or regulatory change to the GRC rates or rules applicable to OPG's prescribed hydroelectric assets under Section 92.1 of the Electricity Act, 1998

Reference 2 states that this proposal is appropriate because both the proposal and the GRC Expense are similar to income and other taxes and the corresponding variance account.

Reference 3 describes water rental charges and costs incurred pursuant to a number of agreements with other government agencies and companies.

Question(s):

a) Please explain the amount of the $352.2 million 2027 GRC Expense that relates to the sum of the following, as described in section 7 of O. Reg 124/02:
   i. New stations
   ii. Redeveloped stations
   iii. Upgraded stations

b) Please provide a breakdown of all components of the $352.2 million 2027 GRC expense in the terms of the types of payments described in Reference 3. Please confirm that the GRC VA proposal would include any changes to all types of payments that form the $352.2 million GRC expense. In not confirmed, please explain. Please also explain whether there are any potential expenses currently not included in the $352.2 million expense that OPG proposes to be in scope of the GRC VA

c) Please confirm that both of the ways OPG proposes to revise the GRC VA are symmetrical. If not, please explain.

d) With illustrative examples, please explain the interaction between the GRC Factor and the proposed expanded GRC VA. For example, if the proposed GRC VA had additions in one of the years from 2028 to 2031, what would be the net effect on the GRC expense to OPG for that year and the GRC expense in the illustrative revenue requirement that corresponds to the payment amount of that year.

e) Please list all deferral and variance accounts (DVAs) that have a GRC expense component to their additions. With illustrative examples, such as example journal entries, please explain the interaction between changes to the GRC expense payable by OPG and all DVAs with GRC expenses associated with their additions. Please provide an explanation of the GRC expenses for each of the accounts.

f) Please explain why the GRC Factor proposal does not include income and other taxes.

Response

a) Section 7 of Ontario Regulation 124/02 (“O. Reg. 124/02”) relates to hydroelectric stations eligible for deductions from GRC expenses. The 2027 GRC expense of $352.2M is a forecast expense and does not include GRC costs from stations eligible for deductions under section 7 of O. Reg. 124/02.

Incremental generation from added station capacity is included in the production forecast and therefore contributes to the GRC expense forecast.

As noted at Ex. F1-4-1, p. 3, lines 13-20,

> “Calabogie GS, which was redeveloped following a tornado in 2017, is currently operating with an approved GRC deduction. No other O. Reg. 124/02 GRC deductions are currently in effect or included in the GRC forecast. OPG expects to apply for GRC deductions for capacity expansions when eligible. As the

eligibility for and magnitude of potential GRC deductions cannot be determined until projects are completed, OPG proposes to capture any future GRC deductions in the Gross Revenue Charge Variance Account. In order to do so, OPG is proposing to expand the existing Gross Revenue Charge Variance Account to apply to all of OPG's regulated hydroelectric facilities."

b) The 2027 GRC expense forecast of $352.2M includes the provincial Gross Revenue Charge and other water agreement costs as described in Ex. F1-4-1. In 2027 this expense is forecast to include $333.1M of GRC, $11.2M of water rental payments to the Province of Québec, $5.2M of fees to the St. Lawrence Seaway Management Corporation, $1.3M of payments to Hydro-Québec, $0.7M of water rental payments to Parks Canada, and multiple other payments less than $0.5M as described in Ex. F1-4-1 and Ex. F1-4-2.

The proposed expanded scope of the Gross Revenue Charge Variance Account discussed in Ex. H1-1-1, Section 5.9 is limited to changes in GRC expense. The proposed scope changes are in relation to potential GRC deductions under O. Reg. 124/02 (for purposes of section 92.1 of the *Electricity Act, 1998*), and revenue requirement impacts of any differences in GRC expenses that result from a legislative or regulatory change to the GRC rates or rules applicable to OPG's prescribed hydroelectric assets under section 92.1 of the *Electricity Act, 1998*. OPG's proposal to expand the account scope does not include impacts in relation to the other water agreements identified above.

c) Confirmed.

d) There is no interaction between the proposed GRCF and the proposed expanded scope of the Gross Revenue Charge Variance Account. The GRCF is designed to hold the GRC expense embedded in payment amounts constant over the IR term. As identified at Ex. H1-1-1, Section 4.1, entries in the Gross Revenue Charge Variance Account would be measured relative to the GRC expense reflected in the approved regulated hydroelectric revenue requirement for the 2027 test year and are not affected by the GRCF. For example, if a change in GRC rates occurred in 2029, OPG would calculate the impact of that change on the GRC expense included in the 2027 revenue requirement, holding all other variables constant.

e) In addition to the Gross Revenue Charge Variance Account, the deferral and variance accounts with a GRC expense component are the Hydroelectric Water Conditions Variance Account ("WCVA") and the Hydroelectric Surplus Baseload Generation Variance Account ("SBGVA").

The WCVA records the financial impact of differences between actual and forecast production at OPG's regulated hydroelectric facilities arising from changes in actual

water conditions. The account records changes in GRC costs from those that underpin the payment amounts approved by the OEB in respect of changes in the regulated hydroelectric production due to differences in water conditions. The account is further described in Ex. H1-1-1, Section 5.1 and a summary of WCVA transactions for 2023 and 2024 is provided at Ex. H1-1-1, Table 2.

The SBGVA records the financial impact of foregone production at OPG's regulated hydroelectric facilities due to surplus baseload conditions. The amounts are net of avoided GRC costs calculated by multiplying the foregone production volume by the applicable GRC rates. The account is further described in Ex. H1-1-1, Section 5.4 and a summary of SBGVA transactions for 2023 and 2024 is provided at Ex. H1-1-1, Table 5.

In both cases, the accounts reflect the relationship between hydroelectric production and GRC costs such that incremental generation relative to forecast results in incremental GRC costs, while a shortfall in generation results in reduced GRC costs. Accordingly, both the WCVA and the SBGVA transactions reflect the associated GRC impacts.

Refer to Ex. L-A1-Staff-273 part (a) for additional information.

f) As noted in the response to part d), the GRCF is designed to hold the GRC expense embedded in payment amounts constant over the IR term. As the GRC expense is deductible for income tax purposes, it does not have an impact on the calculation of regulatory income tax expense for OPG's regulated hydroelectric facilities. Therefore, by adjusting the GRC expense embedded in payment amounts, no further adjustment in relation to income (or other) taxes is required for the GRCF to achieve its stated objective.

Board Staff Interrogatory #271

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / pp. 10-11
Ref 2: Exhibit A1 / Tab 3 / Schedule 2 / pp. 17-20
Ref 3: Exhibit I1 / Tab 2 / Schedule 1 / Table 2

Preamble:

At Reference 1, OPG explains the proposed Inflation Factor, which is a composite index using the same sub-indices that the OEB uses to determine the Inflation Factor for electricity distributors. OPG proposes custom weighting of these two indices.

Reference 2 describes OPG's proposed Capital Factor, including its derivation. Reference 3 is a table that provides the details of the calculation of the Capital Factor for the 2028-31 payment amount setting years.

Question(s):

a) Referencing line 8 of Reference 3, please confirm that the capital related revenue requirement afforded by I-X adjustment is $5,147.6 million for 2027-2031. If not confirmed, please explain.

b) Referencing line 7 of Reference 3, please confirm that OPG's application is presenting a need for $5,346.1 million in Capital Related Revenue Requirement, after capital stretch factor, for the 2027-2031 years. If not confirmed, please explain.

c) Of the total Capital Related Revenue Requirement presented in Reference 3 at line 5, please identify the amounts related to 2027 opening rate base and the amounts related to in-service additions for the 2027-2031 years.

d) Please confirm that it is accurate to state that the Capital Factor is intended to provide $216.5 million in additional revenue requirement to support OPG's presented capital plan. In this case, the $216.5 million is the difference between the amounts in part b) and part a). If not confirmed, please explain.

e) Please explain how the 3.49% forecast inflation relates to capital expenditures, gross plant additions, and OM&A expenses that OPG expects or has forecast for the 2027 to 2031 years. Please explain the methodology for forecasting inflation for the 2027 to 2031 capital plan and the similarities and differences to those of the 3.49% Inflation Factor.

f) Please identify any other inflation related forecasts or assumptions that contribute to the 2027 Test Year revenue requirement or 2028-2031 Capital Related Revenue Requirements. If any such other inflation related forecasts or assumptions exist, please explain the degree to which they are consistent with the 3.49% Inflation Factor.

g) Please confirm that OPG is proposing to fix its Capital Factor for the entire rate term.
   i. If confirmed, please explain how OPG concluded it is appropriate to fix the Capital Factor for the entire rate term. Please ensure this explanation addresses the fact that the Capital Related Revenue Requirement afforded through I-X escalation will change in each subsequent payment amount update proceeding. Please provide any sensitivity analysis that supports the conclusion that this proposal is appropriate.
   ii. If not confirmed, please explain the method by which OPG proposes to update the Capital Factor during the plan term.

Response

a) Not confirmed. As noted in the description column of Ex. I1-2-1, Table 2, line 8, these are the capital-related amounts afforded through the (I-X) adjustment assuming the C-factor applies in prior years. For example, the 2029 value at line 8, col. (c) is $1,011.1M. This is calculated by multiplying the 2028 value at said line 8, col. (b), $906.2M, by the (I-X) adjustment and then adding the 2028 capital related revenue requirement shortfall at such line 9, col. (b), $72.2M. The rationale for this approach is explained in Ex. A1-3-2, p. 20, as follows:

> 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.

The capital-related amounts that would be afforded by the (I-X) adjustment are determined by removing the C-factor entirely, from all years. This results in a total amount of $4,687.5M over the IR term.

b) OPG confirms that the sum of the forecasted regulated hydroelectric capital related revenue requirement amounts after stretch factor, over the IR term, is equal to $5,346.1M at Reference 3.

c) Of the total capital related revenue requirement presented in Reference 3 at line 5, the amount related to the 2027 opening rate base for the regulated hydroelectric facilities is $4,452.4M and the amount related to the forecast 2027-2031 in-service additions is $928.0M. Refer to Ex. L-A1-Staff-275 for further breakdowns of capital related revenue requirement.

d) Not confirmed. The intention of the proposed C-factor is to provide funds incremental to the annual price-cap adjustment in order to support substantial capital investment required at the prescribed hydroelectric facilities during the period. As discussed in part a) above, the total capital-related amount that would be afforded by the (I-X) adjustment is equal to $4,687.5M over the IR term. The difference between the amount of $5,346.1M in part b) and the $4,687.5M in part a) is $676.6M.

e) and f)
The 3.49% is not an OPG inflation forecast. As discussed at Reference 1 in the preamble, 3.49% is the I-factor assumed in OPG's pre-filed evidence, based on the labour and non-labour sub-index values published by the OEB in June 2025, with custom sub-index weighting recommended by London Economics International. In Ex. L-A1-Staff-004, OPG recalculated the I-factor to be 2.9% based on 2025 data.

Refer to Ex. L-A2-CCC-015 for discussion on OPG's escalation forecast for the 2027-2031 period.

g) Refer to Ex. L-A1-CCC-003.

Board Staff Interrogatory #273

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / pp. 9, 20-21
Ref 2: Exhibit F1 / Tab 4 / Schedule 1
Ref 3: Exhibit F1 / Tab 4 / Schedule 1 / Table 1

Preamble:

At Reference 1, OPG explains the proposed gross revenue charges (GRC) Factor. Reference 2 describes the GRC and other water agreement costs. Reference 3 shows the total GRC Expense paid to either the Ministry of Finance or other government agencies and companies.

Question(s):

a) Please complete the following table, where 2016 to 2024 actual GRC expense is from Reference 3:

Table 1: Summary of GRC Expense

Line #		2016	2017	2018	2019	2020
1a	Annual Production [GWh]					
2a	Actual Gross Revenue [$ millions]					
3a	Actual GRC Expense [$ millions]	312.7	319.7	319.2	324.5	323.4
4a	Water Conditions Variance Account (WCVA) Calculated Production Difference [GWh]					
5a	Total WCVA Revenue [$ millions]					
6a	Total WCVA GRC [$ millions]					
7a	Surplus Baseload Generation Forgone Production [GWh]					
8a	Total Surplus Baseload Generation Variance Account (SBGVA) Revenue [$ millions]					
9a	Total SBGVA GRC [$ millions]					
10a	Overall Production [Lines 1a + 4a + 7a]					

Witness Panel: Hydroelectric Operations and Hydroelectric Projects, and Market Renewal Program

Line #		2016	2017	2018	2019	2020
11a	Overall Revenue with variance account (VA) impacts [Lines 2a + 5a + 8a]					
12a	Overall GRC Expense [Lines 3a + 6a + 9a]					

Line #		2021	2022	2023	2024	2025
1b	Annual Production [GWh]					
2b	Actual Gross Revenue [$ millions]					
3b	Actual GRC Expense [$ millions]	315.7	330.3	336.7	348.6	
4b	WCVA Calculated Production Difference [GWh]					
5b	Total WCVA Revenue [$ millions]					
6b	Total WCVA GRC [$ millions]					
7b	Surplus Baseload Generation Forgone Production [GWh]					
8b	Total SBGVA Revenue [$ millions]					
9b	Total SBGVA GRC [$ millions]					
10b	Overall Production for Revenue, including VAs [Lines 1b + 4b + 7b]					
11b	Overall Revenue with VA impacts [Lines 2b + 5b + 8b]					
12b	Overall GRC Expense [Lines 3b + 6b + 9b]					

b) Please comment on any overall trends from the 2016 to 2025 period on the relationship between Actual Production and Actual GRC expense, referencing Lines 1 and 3 in the table in part a). Please confirm that, generally, the production upon which GRC expense is based is the same production as that which OPG settles with the IESO. If not confirmed, please explain.

c) Please comment on any overall trends from the 2016 to 2025 period on the relationship between the overall production that includes the impact of variance accounts and the GRC expense that includes the GRC impact to those accounts, referencing Lines 10 and 12 in the table in part a). Please confirm that, generally,

there are no other deferral or variance accounts that relate to hydroelectric production or that otherwise true-up differences between forecast and actual production related revenue for the regulated hydroelectric generating stations. If not confirmed, please explain.

d) Please explain how OPG is presenting an increase in GRC Expense for the 2027 Test Year with a decrease in annual production, when compared to the OEB approved EB-2013-0321 GRC expense and production.

e) Please confirm that the GRC Expense presented in Reference 3 includes payments to other government agencies, such as the Government of Québec Water Rentals. If not confirmed, please explain.

Response

a) Refer to Attachment 1.

b) Confirmed. Production amounts for the purposes of settling Gross Revenue Charge ("GRC") expenses and settling production with the IESO are generally the same. The two measurements utilize the same revenue meter for purposes of measuring production, and any differences between the two amounts can be explained by reasons such as radial line losses, transformation losses and compliance aggregation which are only applied in the process of settlement with the IESO.

There is a strong correlation between Annual Production and Actual GRC expense. Variations in rates of change between the two quantities are due to station-level differences in yearly production and the corresponding interaction between the graduated tiers of GRC property tax rates as detailed in Ex. F1-4-1, Section 3.0.

c) OPG confirms that the Hydroelectric Water Conditions Variance Account ("WCVA") and Hydroelectric Surplus Baseload Generation Variance Account ("SBGVA") are the only variance accounts which true-up differences between forecast and actual regulated hydroelectric production-revenue from payment amounts. Additionally, the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account trues up differences between such forecast and actual production-related revenue (or reduction thereto) from payment amount riders for disposition of approved deferral and variance account balances (Ex. H1-1-1, Section 5.8).

There is less correlation between the Overall Production and Overall GRC expense than was presented above in Part b). This can be explained by the fact that Actual Production (Line 1) and SBG Forgone Production (Line 7) occur on an actual basis, reflecting prevailing water conditions, unit outages and market conditions.

Conversely, as detailed in Ex. H1-1-1, Section 5.1, the WCVA Calculated Production amount (Line 4) is a modeled production value which utilizes the production forecast models approved in EB-2013-0321. This methodological difference, under certain conditions, decouples the sum of Actual Production and SBG Forgone Production from the WCVA Calculated Production, leading to potential differences in the graduated tiers of GRC property tax rates. As a result, correlations in the Overall Production and Overall GRC expenses may vary.

The complex interaction of the Actual Production GRC expense, the SBGVA GRC expense and WCVA GRC expense in the historical period needs to be considered on a station-level basis in detail in order to evaluate potential correlation.

d) OPG is not seeking approval for an increase in GRC expense in the 2027 Test Year with a decrease in annual production. As shown in Chart 1 below, both forecast GRC expense and regulated hydroelectric production in 2015 were higher than the amounts proposed for 2027. The annualized OEB-approved 2014 regulated hydroelectric production is consistent with the production proposed for 2027, with a lower GRC expense. This reflects the fact that GRC expense is influenced not only by total generation volumes, but also by regional production mixes, since different generating stations are subject to different GRC rates and the GRC framework is tiered based on volume.

In addition, the GRC expense also includes water rental costs outside of the provincial GRC regime, some of which are subject to CPI adjustment as described in Ex. F1-4-1 and Ex. F1-4-2.

Chart 1
OEB-Approved (2014/2015) and OPG Proposed (2027) Regulated Hydroelectric Production and GRC[1]

Year	Production	GRC Expense
2014 (Annualized OEB Approved)	32.5TWh	$342.8M
2015 (OEB Approved)	33.5TWh	$358.3M
2027 (OPG Proposed)	32.5TWh	$352.2M

[1] 2014 (Annualized) and 2015 OEB-Approved Production: EB-2013-0321, OEB Decision and Order, p. 9
2027 OPG Proposed Production: Ex. E1-1-1 Table 1, line 4, col. (m).
2014 (Annualized) OEB-Approved GRC Expense: EB-2013-0321, Payment Amounts Order, App. A: Table 1, line 16, col. (c) and Table 2, Line 16, col. (c).
2015 OEB-Approved GRC Expense: EB-2013-0321, Payment Amounts Order, App. A: Table 1, Line 16, col. (f) and Table 2, Line 16, column (f).
2027 OPG Proposed GRC Expense: Ex. F1-4-1 Table 1, line 9, col. (c).

Witness Panel: Hydroelectric Operations and Hydroelectric Projects, and Market Renewal Program

e) Confirmed, although approximately 95% of the total expenses are GRC payments to the Province of Ontario.

Ex. L-A1-Staff-273 - Attachment 1

Line #		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
1	Annual Production [GWh]	29,459	30,685	29,768	30,538	30,270	28,971	31,073	31,410	32,489	30,886
2	Actual Gross Revenue [$ millions]	$ 1,298.9	$ 1,274.0	$ 1,268.2	$ 1,379.9	$ 1,376.1	$ 1,333.9	$ 1,404.2	$ 1,416.3	$ 1,508.0	$ 1,458.4
3	Actual GRC Expense [$ millions]	$ 312.7	$ 319.7	$ 319.2	$ 324.5	$ 323.4	$ 315.7	$ 330.3	$ 336.7	$ 348.6	$ 333.8
4	Water Conditions Variance Account (WCVA) Calculated Production Difference [GWh]	(1,123)	(3,262)	(1,581)	(2,136)	(2,227)	751	(2,384)	(1,466)	(1,218)	411
5	Total WCVA Revenue [$ millions]	$ (44.8)	$ (135.3)	$ (66.5)	$ (90.8)	$ (96.1)	$ 32.9	$ (104.6)	$ (64.3)	$ (53.5)	$ 18.0
6	Total WCVA GRC [$ millions]	$ 11.8	$ 37.3	$ 25.9	$ 29.8	$ 33.5	$ 7.8	$ 33.6	$ 23.1	$ 18.4	$ 0.3
7	Surplus Baseload Generation Forgone Production [GWh]	4,269	5,225	3,220	3,301	4,315	1,882	1,592	977	350	751
8	Total Surplus Baseload Generation Variance Account (SBGVA) Revenue [$ millions]	$ 174.2	$ 215.7	$ 135.3	$ 139.8	$ 186.2	$ 82.6	$ 69.9	$ 42.9	$ 15.3	$ 33.0
9	Total SBGVA GRC [$ millions]	$ (48.7)	$ (68.5)	$ (42.0)	$ (42.4)	$ (55.8)	$ (26.2)	$ (22.0)	$ (13.2)	$ (4.7)	$ (9.7)
10	Overall Production [Lines 1a + 4a + 7a]	32,605	32,648	31,407	31,703	32,358	31,604	30,281	30,921	31,621	32,048
11	Overall Revenue with variance account (VA) impacts [Lines 2a + 5a + 8a]	$ 1,428.3	$ 1,354.4	$ 1,337.0	$ 1,428.9	$ 1,466.2	$ 1,449.4	$ 1,369.5	$ 1,394.9	$ 1,469.8	$ 1,509.4
12	Overall GRC Expense [Lines 3a + 6a + 9a]	$ 275.8	$ 288.5	$ 303.1	$ 311.9	$ 301.1	$ 297.3	$ 341.9	$ 346.6	$ 362.3	$ 324.4

Board Staff Interrogatory #274

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / pp. 9, 20-21
Ref 2: Exhibit F1 / Tab 4 / Schedule 1 / Chart 2

Preamble:

Reference 1 describes the proposed gross revenue charges (GRC) Factor. Reference 2 provides the station production groupings for the GRC. It also provides the Total GRC Rate as a percentage.

Question(s):

a) Please confirm the value to which the Total GRC Rate, as a percentage, is applied to determine a dollar-based rate. Please provide the source of that value.

b) For each year of 2016 to 2025, please identify all the hydroelectric generating stations that were in a different Station Production grouping than in the previous year. For each station that is identified, please quantify the impact of that change in grouping on the annual GRC expense of that generating station.

   For example, if Station A was in the 400-700 group in 2018 and in the >700 group in 2019, OEB staff requests the response to be structured similar to the following:
   - 2019:
     - Station A: [numerical difference in GRC Expense of 2019 less 2018 in $ million to one decimal place]

c) Please generally explain, in the context of the 2016 to 2025 historical period, the impact of a given generating station changing from one grouping to another. For example, what is the impact on the GRC expense for that generating station that is in the >700 GWh group when it was in the 400-700 GWh group in the previous year? The GRC Rate is more than double, so is the GRC expense more than double the expense in the previous year?

Response

a) The Total GRC Rate in Reference 2 is applied to a value of $40,000/GWh (as prescribed by O. Reg. 124/02 and extended by Ontario Regulation 18 09/10), as

set out in the Province of Ontario document[1] "Gross Revenue Charges for Hydro-electric Generating Stations".

b) The changes in GRC expense year-over-year associated with regulated hydroelectric stations which also changed GRC Property Tax rate tiers during that year are as follows:

2017 (2017 GRC Expense – 2016 GRC Expense):

- Big Chute GS: $0.2 M
- Matabitchuan GS: $0.04 M
- Caribou Falls GS: -$0.7 M
- Pine Portage GS: $0.8 M
- Barrett Chute GS: $1.0 M
- Mountain Chute GS: $1.1 M
- Stewartville GS: $1.2 M
- DeCew Falls 2 GS: -$3.6 M

2018 (2018 GRC Expense – 2017 GRC Expense):

- Big Chute GS: -$0.1 M
- Matabitchuan GS: -$0.05 M
- Alexander GS: -$0.5 M
- Caribou Falls GS: $0.2 M
- Barrett Chute GS: -$1.7 M
- Mountain Chute GS: -$1.2 M
- Stewartville GS: -$1.3 M
- DeCew Falls 2 GS: $0.1 M

2019 (2019 GRC Expense – 2020 GRC Expense):

- Matabitchuan GS: $0.02 M
- Alexander GS: $0.4 M
- Caribou Falls GS: $0.9 M
- DeCew Falls 2 GS: $0.9 M

2020 (2020 GRC Expense – 2019 GRC Expense):

- Matabitchuan GS: $0.02 M
- Alexander GS: -$0.4 M
- Caribou Falls GS: -$0.4 M
- Pine Portage GS: -$0.5 M
- Ranney Falls GS: $0.03 M

[1]Province of Ontario, Document: Gross Revenue Charges for Hydro-electric Generating Stations, March 22, 2022. <https://www.ontario.ca/document/gross-revenue-charges-hydroelectric-generating-stations#section-0>

2021(2021 GRC Expense – 2020 GRC Expense):

- Matabitchuan GS: -$0.1 M
- Alexander GS: -$0.3 M
- Cameron Falls GS: -$0.5 M
- Caribou Falls GS: -$0.5 M
- Pine Portage GS: $0.5 M
- Silver Falls GS: -$0.4 M

2022 (2022 GRC Expense – 2021 GRC Expense):

- Lower Notch GS: $0.7 M
- Alexander GS: $0.6 M
- Cameron Falls GS: $1.0 M
- Caribou Falls GS: $1.0 M
- Silver Falls GS: $0.1 M

2023 (2023 GRC Expense – 2021 GRC Expense):

- Big Chute GS: $0.1 M
- Lower Notch GS: $0.2 M
- Alexander GS: -$1.3 M
- Caribou Falls GS: -$1.0 M
- Silver Falls GS: $0.8 M

2024 (2024 GRC Expense – 2023 GRC Expense):

- Big Chute GS: -$0.1 M
- Lower Notch GS: $0.3 M
- Caribou Falls GS: $0.7 M
- DeCew Falls 2 GS: -$2.7 M

2025 (2025 GRC Expense – 2024 GRC Expense):

- Lower Notch GS: -$0.9 M
- Caribou Falls GS: -$0.5 M
- DeCew Falls 2 GS: $3.5 M
- Kakabeka Falls GS: -$0.1 M

c) The GRC rate is applied as a tiered tax rate. If a station was to generate 750 GWh in a given year, the following GRC Property tax rates would apply:
   1. For the first 50 GWh, the property tax rate would be 2.5%.
   2. The 50-400 GWh would be taxed at 4.5%.
   3. The 400-700 GWh would be taxed at 6.0%.
   4. Only the 50 GWh beyond 700 GWh would be taxed at the highest tier rate of 26.5%.

This means that when a station enters the 700 GWh tier, the GRC expense begins to accumulate more quickly, but it does not double.

Board Staff Interrogatory #276

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 1 / pp. 17-20
Ref 2: Exhibit D1 / Tab 1 / Schedule 2 / Table 4
Ref 3: Exhibit F4 / Tab 1 / Schedule 1 / Attachment 7 / Table 1
Ref 4: Exhibit I1 / Tab 2 / Schedule 1 / Table 2

Preamble:

Reference 1 describes the proposed Capital Factor and its intended design to recover sufficient revenue to support OPG's need for ongoing investments in OPG's hydroelectric assets.

Reference 2 provides historical and planned in-service additions for the 2016 to 2031 period. This table does not provide insight into the types of in-service additions.

OEB staff would like to better understand the revenue requirement impact of historical hydroelectric in-service additions. OEB staff would like to do so on the basis of grouping the assets in hydroelectric rate base by general function and range of asset life. To support this interrogatory, OEB staff has used Reference 3 to categorize the assets in hydroelectric rate base.

OEB staff has grouped the assets into the following categories:

Table 1: Categorization of Hydroelectric Asset Accounts

Category	Account	Account Description
Buildings	**10210000**	Hydroelectric - Service and Equipment Buildings
	10315000	Hydroelectric - Steel Racks
	10709000	Hydroelectric - Owned Bridges, Railway Tracks and Wharves
	16210000	Administrative and Service Buildings - Perm Buildings, Roads and Site Improvements
	18200000	Communications - Buildings
Electrical and Auxiliary	**10201000**	Hydroelectric - Roofing
	10202000	Hydroelectric - Fencing
	10318000	Hydroelectric - Gates, Stoplogs and Operating Mechanisms
	10500000	Hydroelectric - Main Rotating Electrical Pilots - Windings
	10502000	Hydroelectric - Bus, Switching and Power Cables
	10503000	Hydroelectric - High Voltage Switching

Witness Panel: Finance, D&V, Cost of Capital, Regulatory Constructs, Customer Impacts

Category	Account	Account Description
	10503100	Hydroelectric - Revenue Metering - High Voltage Switching, Control Boards / Switchboards
	10504000	Hydroelectric - Control Boards and Switchboards
	10505000	Hydroelectric - Station Service Electrical Equipment
	10510000	Hydroelectric - Main Power and Station Service - Transformers
	10531000	Hydroelectric - Circuit Breakers
	10700000	Hydroelectric - Auxiliary Systems
	11200000	Transfer and Distribution Stations - Buildings
	16230000	Administrative and Service Buildings - Buildings - Frame & Metal Clad
	18530000	Communications - Timber and Steel Structures
	18600000	Communications - Poles and Cables
	18630000	Communications - Optical Wire
	18633000	Communications - Optical Wire - Revenue Metering
Equipment	**10302100**	Hydroelectric - Public Safety/Warning Booms
	10710000	Hydroelectric - Fire Protection Systems
	10720000	Hydroelectric - Electronic Security Systems
	16540000	Administrative and Service Buildings - Administrative Telecom Equipment
	16550000	Administrative and Service Buildings - LAN Cable
	16630000	Administrative and Service Buildings - Building Systems and Equipment
	18400000	Communications - Power Line Equipment
	18440000	Communications - System Control Computer Equipment
	18460000	Communications - Data Acquisition Equipment, Human Machine Interface Equipment
	18500000	Communications - Radio Equipment
	18540000	Communications - Administrative Telecom Equipment
	18541000	Communications - Administrative Telecom Equipment - Revenue Metering
	18700000	Communications - Power Supply Equipment
	SERV1	Minor Fixed Assets - Service Equipment
	T&WE1	Transportation and Work Equipment
Hydraulic Structures	**10300000**	Hydroelectric - Canal, Forebay, Retaining Wall Lining
	10301000	Hydroelectric - Lining of Tunnels and Permanent Shafts
	10301100	Hydroelectric - Lining of Tunnels and Permanent Shafts (90Y)
	10302000	Hydroelectric - Spillways, Sluices, Flumes
	10306000	Hydroelectric - Surgetank, Pipeline, Conduit, Penstock
	10000100	Hydroelectric - Intangibles

Category	Account	Account Description
Land Structures and Misc	**10100000**	Hydroelectric - Land Improvements
	10101000	Hydroelectric - Excavation, Dredging, Riprapping, Grouting
	10110000	Hydroelectric - Land - pre - 1999
	10200000	Hydroelectric - Substructures and Superstructures
	10205000	Hydroelectric - Outdoor Structures
	10311000	Hydroelectric - Dams - Earth and Rockfill
	10312000	Hydroelectric - Dams - Concrete
	10991000	Hydroelectric - Major / Strategic Spares
	16100000	Administrative and Service Buildings - Lands
	18100000	Communications - Land
Mechanical	**10400000**	Hydroelectric - Turbines & Governors
	10405000	Hydroelectric - Turbine Runners
	10501000	Hydroelectric - Main Rotating Electrical Pilots - Machinery less Windings
	10601000	Hydroelectric - Mechanical Equipment - Cranes and Followers
Other	**16211000**	Administrative and Service Buildings - Buildings - Leased
	16220000	Administrative and Service Buildings - Buildings
	16551000	Administrative and Service Buildings - LAN Elect Connecting Devices
	16560100	Administrative and Service Buildings - Intangibles Administrative System Software
	COMP1	Computers
	OFFICE1	Office Furniture and Fixtures

Question(s):

a) Please provide the actual in-service additions for each year of 2020 to 2025 by category presented in the preamble.

b) For each year of 2020 to 2025, please provide a breakdown of the Capital Related Revenue Requirement for each category. Please ensure the breakdown shows the associated cost of debt, return on equity, depreciation, and income taxes. Please do so on the basis of the OEB approved parameters that were actually in place in those years.

c) Please provide a breakdown of any other revenue requirement impacts, in each year, OPG assesses to be directly attributable to those in-service additions. Please explain each revenue requirement impact and explain how they are directly related to those in-service additions.

Witness Panel: Finance, D&V, Cost of Capital, Regulatory Constructs, Customer Impacts

d) Please repeat parts a) through c) exclusively for CRVA-eligible projects as questions d), e), and f).

Response

a) Refer to Attachment 1.

b) and c)

OPG declines to provide the requested calculation at the category account level as this level of granularity is impractical and unnecessary for a revenue requirement analysis.

For illustrative purposes, Chart 1 below provides a calculation for the 2020-2025 period that is equivalent to a hypothetical total annual capital-related revenue requirement for the regulated hydroelectric facilities, based on actual rate base, depreciation and amortization and income tax expense, and the OEB-approved cost of capital parameters underpinning the regulated hydroelectric payment amounts in effect during the period. In providing this information, OPG notes that the OEB did not review or approve any hydroelectric capital-related revenue requirement for the 2022-2026 period as the payment amounts were legislatively frozen pursuant to O. Reg. 53/05, section 6(2)13.

Chart 1 – Hypothetical Total Annual Hydroelectric Capital-Related Revenue Requirement for 2020-2025

Line No.	Description	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual
1	**Depreciation & Amortization**[1]	145.0	146.4	154.4	161.3	168.3	176.6
2	**Cost of Capital – Debt**[2]	199.0	200.3	205.9	212.6	216.2	220.4
3	**Cost of Capital - ROE**[2]	312.2	314.2	323.0	333.5	339.2	345.9
4	**Income Tax**[3]	93.0	87.9	103.8	60.2	(3.3)	79.4
5	**Capital-Related Revenue Requirement**	749.2	748.7	787.1	767.6	720.4	822.3

[1] 2020 to 2024 per Ex. F4-1-1, Table 1, lines 1 + 2 + 3, cols. (e) to (i), respectively. 2025 per Ex. L-A1-CCC-001, Attachment 1, Table 54, lines 1 + 2 + 3, col. (j).

[2] Cost of Capital calculations are as follows:

Line No.	Description	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Actual	2025 Actual
2a	**Net Plant Rate Base***	7,460.8	7,507.7	7,719.0	7,969.6	8,104.9	8,264.2
2b	**Weighted Cost of Capital - Debt (%)****	2.67%	2.67%	2.67%	2.67%	2.67%	2.67%
2c	**Cost of Capital - Debt ($)** (line 2a x line 2b)	199.0	200.3	205.9	212.6	216.2	220.4
2d	**Weighted Cost of Capital - ROE (%)*****	4.19%	4.19%	4.19%	4.19%	4.19%	4.19%
2e	**Cost of Capital - ROE ($)** (line 2a x line 2d)	312.2	314.2	323.0	333.5	339.2	345.9

* 2020-2021 per Ex. B1-1-1, Table 1, line 3, cols. (h) to (i); 2022-2024 per line 9, cols. (a) to (c), respectively. 2025 per Ex. L-A1-CCC-001, Attachment 1, Table 3, line 4, col. (f) less Table 4, line 4, col. (f).

** Calculated as EB-2013-0321 Payment Amounts Order, App. A, Table 6b, line 4, col. (b) x (c).

*** Calculated as EB-2013-0321 Payment Amounts Order, App. A, Table 6b, line 5, col. (b) x (c).

[3] 2020 to 2024 per Ex. F4-2-1, Table 1, line 1, cols. (e) to (i). 2025 per Ex. L-A1-CCC-001, Attachment 1, Table 56, line 1, col. (j). The entirety of regulatory income tax expense is included on the basis that it is predominantly (though not entirely) capital-related (refer to Ex. L-F4-Staff-220, part (a)(ii)).

d) to f)

OPG declines to provide the requested analysis. For the hydroelectric components of the Capacity Refurbishment Variance Account ("CRVA"), for the reasons set out in Ex. L-H1-Staff-260, part b), OPG can only seek recovery after the end of an IR term. Since the information for the current 2022-2026 IR term is unavailable until the term concludes, the recoverable amount in the account cannot be determined or cleared during this proceeding. As such, the requested information is not relevant to this proceeding. Refer to Ex. L-A1-SEC-010 for a demonstration of how the CRVA interacts with the previously approved price-cap mechanism for the regulated hydroelectric facilities.

Numbers may not add due to rounding

Filed: 2026-04-22
EB-2025-0297
Exhibit L
A1-Staff-276
Attachment 1
Table 1

Table 1
Actual Regulated Hydroelectric In-Service Additions from 2020-2025 ($M)
In-Service Additions by Category for 2020, 2021, 2022, 2023, 2024 and 2025

Line No.	Category	Account	Account Description	Note	In-Service Additions 2020	In-Service Additions 2021	In-Service Additions 2022	In-Service Additions 2023	In-Service Additions 2024	In-Service Additions 2025
					(a)	(b)	(c)	(d)	(e)	(f)
1	Buildings	10210000	Hydroelectric - Service and Equipment Buildings		4.2	0.7	3.2	1.0	0.0	2.3
2		10315000	Hydroelectric - Steel Racks		0.0	0.0	0.0	0.7	0.7	4.3
3		10709000	Hydroelectric - Owned Bridges, Railway Tracks and Wharves		1.6	1.4	0.2	0.1	0.0	7.8
4		16210000	Administrative and Service Buildings - Perm Buildings, Roads and Site Improvements		0.0	0.0	0.0	0.0	0.1	0.1
5		18200000	Communications - Buildings		0.0	0.0	0.0	0.0	0.0	0.0
6	**In-Service Additions - Buildings (lines 1 through 5)**				**5.8**	**2.0**	**3.4**	**1.8**	**0.9**	**14.4**
7	Electrical and Auxiliary	10201000	Hydroelectric - Roofing		3.4	12.4	13.5	14.7	8.8	6.9
8		10202000	Hydroelectric - Fencing		0.4	0.0	0.0	0.3	2.6	2.4
9		10318000	Hydroelectric - Gates, Stoplogs and Operating Mechanisms		15.7	35.9	40.2	36.6	25.3	2.4
10		10500000	Hydroelectric - Main Rotating Electrical Pilots - Windings		7.7	4.9	59.8	20.4	17.5	44.3
11		10502000	Hydroelectric - Bus, Switching and Power Cables		4.7	1.2	2.2	16.0	9.2	3.9
12		10503000	Hydroelectric - High Voltage Switching		3.9	8.8	8.5	0.5	2.9	9.3
13		10503100	Hydroelectric - Revenue Metering - High Voltage Switching, Control Boards / Switchboards		0.0	0.0	0.0	0.0	0.0	0.0
14		10504000	Hydroelectric - Control Boards and Switchboards		14.3	18.9	47.1	30.5	8.1	19.0
15		10505000	Hydroelectric - Station Service Electrical Equipment		3.9	10.3	23.8	17.5	14.2	10.3
16		10510000	Hydroelectric - Main Power and Station Service - Transformers		9.1	9.5	9.3	1.1	12.8	1.8
17		10531000	Hydroelectric - Circuit Breakers		0.0	0.0	1.8	0.5	0.0	0.2
18		10700000	Hydroelectric - Auxiliary Systems		6.2	14.0	26.2	11.1	18.8	14.6
19		11200000	Transfer and Distribution Stations - Buildings		0.0	0.0	0.0	0.0	0.0	0.0
20		16230000	Administrative and Service Buildings - Buildings - Frame & Metal Clad		0.0	0.0	1.6	10.6	2.5	9.2
21		18530000	Communications - Timber and Steel Structures		0.0	0.0	0.0	0.0	0.0	2.1
22		18600000	Communications - Poles and Cables		0.0	0.0	0.0	0.0	0.0	0.0
23		18630000	Communications - Optical Wire		0.0	1.3	1.4	0.0	0.3	0.1
24		18633000	Communications - Optical Wire - Revenue Metering		0.0	0.0	0.0	0.0	0.0	0.0
25	**In-Service Additions - Electrical and Auxiliary (lines 7 through 24)**				**69.3**	**117.2**	**235.7**	**159.9**	**122.9**	**126.7**
26	Equipment	10302100	Hydroelectric - Public Safety/Warning Booms		9.0	12.3	2.2	1.8	2.9	3.1
27		10710000	Hydroelectric - Fire Protection Systems		0.0	0.6	0.0	1.3	0.5	1.2
28		10720000	Hydroelectric - Electronic Security Systems		0.1	0.7	0.6	1.7	0.8	0.9
29		16540000	Administrative and Service Buildings - Administrative Telecom Equipment		0.0	0.0	0.0	0.0	0.2	0.4
30		16550000	Administrative and Service Buildings - LAN Cable		0.0	0.0	0.0	0.0	0.0	0.0
31		16630000	Administrative and Service Buildings - Building Systems and Equipment		0.0	0.0	0.0	0.0	0.1	0.0
32		18400000	Communications - Power Line Equipment		0.0	0.0	0.0	0.0	0.0	0.0
33		18440000	Communications - System Control Computer Equipment		0.7	1.5	0.9	0.0	6.1	1.5
34		18460000	Communications - Data Acquisition Equipment, Human Machine Interface Equipment		0.0	1.7	0.1	0.0	0.0	0.3
35		18500000	Communications - Radio Equipment		0.5	0.0	1.2	0.0	0.2	0.0

36		18540000	Communications - Administrative Telecom Equipment		0.0	0.0	0.0	0.0	0.0	0.0
37		18541000	Communications - Administrative Telecom Equipment - Revenue Metering		0.0	0.0	0.0	0.0	0.0	0.0
38		18700000	Communications - Power Supply Equipment		0.0	0.0	0.4	0.0	0.3	0.1
39		SERV1	Minor Fixed Assets - Service Equipment		0.9	0.7	1.1	0.6	1.5	2.7
40		T&WE1	Transportation and Work Equipment		0.0	0.8	0.1	0.7	0.1	5.7
41	**In-Service Additions - Equipment (lines 26 through 40)**				11.1	18.1	6.5	6.1	12.6	15.9
42	Hydraulic Structures	10300000	Hydroelectric - Canal, Forebay, Retaining Wall Lining		0.0	0.0	10.9	1.3	16.2	1.9
43		10301000	Hydroelectric - Lining of Tunnels and Permanent Shafts		0.0	0.0	0.0	0.0	0.0	1.1
44		10301100	Hydroelectric - Lining of Tunnels and Permanent Shafts (90Y)		0.0	0.0	0.0	0.0	0.0	0.0
45		10302000	Hydroelectric - Spillways, Sluices, Flumes		11.2	21.8	12.1	13.1	14.8	11.6
46		10306000	Hydroelectric - Surgetank, Pipeline, Conduit, Penstock		1.2	23.1	1.6	0.1	0.0	0.0
47	**In-Service Additions - Hydraulic Structures (lines 42 through 46)**				**12.5**	**44.9**	**24.6**	**14.5**	**31.0**	**14.6**
48	Land Structures and Misc	10000100	Hydroelectric - Intangibles		2.2	0.0	0.1	-0.4	0.0	0.1
49		10100000	Hydroelectric - Land Improvements		4.7	2.9	3.3	11.5	0.3	12.5
50		10101000	Hydroelectric - Excavation, Dredging, Riprapping, Grouting		0.1	2.2	2.0	3.3	4.4	0.0
51		10110000	Hydroelectric - Land - pre - 1999		0.0	0.0	0.0	0.0	0.0	0.0
52		10200000	Hydroelectric - Substructures and Superstructures		3.0	10.2	110.3	31.9	4.3	6.5
53		10205000	Hydroelectric - Outdoor Structures		0.5	3.2	1.6	7.0	16.9	21.5
54		10311000	Hydroelectric - Dams - Earth and Rockfill		7.9	7.3	1.0	0.0	10.0	9.0
55		10312000	Hydroelectric - Dams - Concrete		1.9	0.7	0.1	0.1	55.8	56.5
56		10991000	Hydroelectric - Major / Strategic Spares		0.0	1.7	3.5	3.1	0.7	1.7
57		16100000	Administrative and Service Buildings - Lands		0.0	0.0	0.0	0.0	0.0	0.5
58		18100000	Communications - Land		0.0	0.0	0.0	0.0	0.0	0.0
59	**In-Service Additions - Land Structures and Misc (lines 48 through 58)**				**20.2**	**28.1**	**121.9**	**56.5**	**92.5**	**108.2**
60	Mechanical	10400000	Hydroelectric - Turbines & Governors		3.0	16.3	37.3	16.6	3.6	66.4
61		10405000	Hydroelectric - Turbine Runners		9.5	13.9	36.9	0.2	20.0	28.4
62		10501000	Hydroelectric - Main Rotating Electrical Pilots - Machinery less Windings		5.2	6.3	26.0	0.5	0.3	0.9
63		10601000	Hydroelectric - Mechanical Equipment - Cranes and Followers		9.1	2.2	31.7	12.7	23.1	17.8
64	**In-Service Additions - Mechanical (lines 60 through 63)**				**26.8**	**38.8**	**131.8**	**29.9**	**47.1**	**113.5**
65	Other	16211000	Administrative and Service Buildings - Buildings - Leased		0.0	0.0	0.0	0.0	0.0	0.0
66		16220000	Administrative and Service Buildings - Buildings		0.0	0.0	0.0	0.0	38.6	0.4
67		16551000	Administrative and Service Buildings - LAN Elect Connecting Devices		0.0	0.0	0.0	0.0	0.0	0.0
68		16560100	Administrative and Service Buildings - Intangible Administrative System Software		0.0	0.0	0.0	0.0	2.3	0.3
69		COMP1	Computers		0.2	0.0	0.1	0.1	0.0	0.0
70		OFFICE1	Office Furniture and Fixtures		0.0	0.0	0.0	0.0	0.0	0.2
71	**In-Service Additions - Other (lines 65 through 70)**				**0.2**	**0.0**	**0.1**	**0.1**	**40.9**	**0.9**
72	**Total Regulated Hydroelectric In-Service Additions (line 6 + line 25 + line 41 + line 47 + line 59 + line 64 + line 71)**			**1**	**145.9**	**249.3**	**524.0**	**268.8**	**347.8**	**394.1**

Notes:

1 Cols. (a) to (e) per Ex. D1-1-2, Table 4, line 18, cols. (e) to (i). Col. (f) per Ex. L-01-CCC-001, Attachment 1, Table 14, line 18, col (j).

Board Staff Interrogatory #277

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 1
Ref 2: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 2
Ref 3: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 3

Preamble:

A significant amount of time has passed since London Economics International LLC (LEI) had performed its analysis for this proceeding. Research of this kind is complex, and LEI may have found some issues with their research and report since they finished their work or when preparing interrogatory responses. This question provides an opportunity for LEI to make corrections, adjustments, and/or clarifications to their work.

Question(s):

a) Are there any corrections, adjustments, clarifications, or other changes to the research or the report that LEI would like to make at this time?

b) If so, please provide an updated report and/or working papers and briefly describe the upgrades here.

Response

This response was prepared by London Economics International LLC ("LEI")

a) Yes, LEI would like to make a minor typographical correction to the TFP report. As discussed in response to Ex. L-A1-Staff-280 part (i) below, the typographical error appears in Appendix B of the TFP report, specifically in one notation used to present the implicit rental price formula. However, this typographical error does not in any way impact LEI's TFP analysis nor its results.

b) The implicit rental price formula shown in Appendix B should be changed from:

$$PK_t = \frac{1-uz}{1-u}(r-i)\left[1-\left(\frac{1+i}{1+r}\right)^s\right]^{-1} BLS_PPI_{t-1}$$

to:

$$PK_t = \frac{1-uz}{1-u}(r-i)\left[1-\left(\frac{1+i}{1+r}\right)^s\right]^{-1} HWI_{t-1}$$

The change is with regards to the notation of the last component of the formula, which should read HWI_{t-1}, not BLS_PPI_{t-1}. This change reflects the fact that LEI used the Handy Whitman Cost Index ("HWI") for Hydraulic Production Plant as the capital cost index to convert all retirements and additions into constant dollar terms (2002 dollars), not the United States Bureau of Labor Statistics ("BLS") Producer Price Index ("PPI"). This is confirmed on page 40 of LEI's TFP report, which reads:

> *"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") for Hydraulic Production Plant to represent all retirements and additions in 2002 dollars, which reflects the start year of the TFP study timeframe."*

As noted above, the typographical error appearing in Appendix B of the TFP report does not in any way impact LEI's TFP analysis, workpapers, or the results.

Board Staff Interrogatory #278

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 2 / page 34
Ref 2: EB-2016-0152 / Exhibit A1 / Tab 3 / Schedule 2 / Attachment 1 / p. 8
Ref 3: Exhibit YGS-PBR-1 in Connecticut PURA Docket No. 24-12-01
Ref 4: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 3

Preamble:

London Economics International LLC (LEI) states on p. 34 of its productivity report that "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." The tendency of the hydroelectric generation volume of sampled utilities to grow more slowly than capacity is a major reason for the negative Total Factor Productivity (TFP) trend that LEI reports. The relevance of this trend disparity for Ontario ratemaking depends on whether OPG, whose hydro facilities are located near the Great Lakes in a humid continental climate, is experiencing it.

Question(s):

a) What, in LEI's view, is the relative importance of hydroelectric generation volume and capacity as drivers of generation cost?

b) LEI stated on page 18 of its benchmarking report that "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." Why is generation volume used as the sole scale variable in LEI's productivity research when generation capacity is the scale variable in LEI's econometric cost model and generation volume is not included in this model?

c) What output metric would make the most sense if OPG had proposed a revenue cap index instead of a price cap index?

d) Please confirm that LEI used the number of customers served to measure output growth in a recent TFP study for Yankee Gas in Connecticut, stating that:

> Gas sales, which LEI also considered as an output, are primarily driven by weather patterns that can vary considerably across time, irrespective of the costs incurred and inputs employed by the LDC. In other words, operational procedures and capital investment plans will not necessarily change in response to weather variability year over year. Therefore, the use of gas sales

> as an output metric may introduce volatility in the TFP index that is not truly reflective of the industry's physical productivity trends…Additionally, gas LDCs typically build pipeline systems to serve customers and not necessarily the specific amount of gas consumed per customer, as that is likely to change with time.

How does LEI reconcile this commentary with advocacy of generation sales volume as the output variable for its OPG productivity study?

e) Please confirm that generation capacity is sold in several bulk power markets, including those in several American regions that are adjacent to Ontario. A dramatic rise in capacity prices in bulk power markets managed by PJM has recently reduced the affordability of power in the region that it serves considerably. If not confirmed, please explain.

f) Has LEI considered taking a weighted average of the growth in generation volume and capacity to measure scale growth in the productivity study? What weights would make sense in such an average?

Response

This response was prepared by London Economics International LLC ("LEI")

a) Based on the preamble, LEI understands that this question refers to LEI's TFP study. For the purposes of the TFP study, LEI chose to use annual generation measured in MWh as the single output measure. This is consistent with the methodology used in LEI's 2016 TFP Study, and is also consistent with the OEB's 2017 Decision, which as stated on page 34 of LEI's TFP report:

> *"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."*

Furthermore, as stated on page 16 of the TFP report:

> *"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."*

b) LEI used annual generation measured in MWh as the measure of output in the TFP study, not as the "sole scale variable." For the benchmarking study, the annual capacity measured in MW was indeed used as a way to adjust or control the costs for scale of the facilities. Therefore, these measures were serving different primary purposes in their respective studies.

LEI's reasoning for using generation as the single output measure in the TFP study was provided above in response to part (a) of this IR.

As for the benchmarking study, LEI used capacity as the scaling factor because, as stated on page 11 of the benchmarking report:

> *"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."*

Notably, similar to LEI's benchmarking study, LEI understands that EUCG also controls for plant capacity (not generation) in its benchmarking analysis to reflect economies of scale in costs.

c) OPG has proposed a price cap index as part of its application, not a revenue cap. Nonetheless, even under a revenue cap index, LEI believes that it still makes sense to use annual generation measured in MWh as the output measure. This is because the TFP study is intending to measure productivity of the businesses in the industry, and as indicated above in response to part (a) of this IR (and as stated in the OEB's 2017 Decision), "*[t]he 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.*"[1]

[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. P. 126.

d) LEI confirms that in its 2024 study of TFP for the US gas distribution industry, it used number of customers as an output metric, as well as gas sales (as a sensitivity test).

Natural gas distribution (i.e., the focus of the Yankee Gas proceeding in Connecticut referenced in the question) is an entirely different business than electricity generation (which is the focus of this proceeding). LEI's reasoning for using generation as the single output measure in this TFP study of the hydroelectric generation industry is provided above in response to part (a) of this IR.

e) LEI can confirm the first part of the question, namely that capacity markets are in place in several regions across the US, as well as in Ontario. LEI will not comment on the second part of the question regarding affordability. We do not believe this question is relevant to our analysis.

f) LEI did not consider using a weighted average multi-output index for this TFP study. For that reason, we have not considered what weights would "make sense."

Board Staff Interrogatory #279

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 2
Ref 2: Exhibit F1 / Tab 1 / Schedule 1 / Table 1
Ref 3: EB-2016-0152 / Exhibit A1 / Tab 3 / Schedule 2 / Attachment 1 / p. 8
Ref 4: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 2 / Confidential Working Papers

Preamble:

After reviewing London Economics International LLC (LEI)'s productivity report and working papers, PEG has several additional questions.

Question(s):

a) LEI calculates the Total Factor Productivity (TFP) trend of hydro generators using a sample period with 21 growth rate years. In reference 3, however, LEI defended a 13-year sample period in the 2016 proceeding and not a longer period by stating in response to an interrogatory that "[b]ecause an industry TFP study reports historical productivity growth rates, care must be applied to ensure that going forward business conditions are similar to those that prevailed historically." However, on p. 22 of its productivity report in this proceeding LEI states that "LEI believes that the longest timeframe allowed by the availability of data (2002-2023) is appropriate for this study."

   i. Please confirm that a shorter sample period like the 15 years commonly used in Massachusetts IR evidence would produce a more rapid industry TFP trend.
   ii. Why is LEI opting for a much longer TFP trend now?

b) The working papers provided appear to have all the information required for a calculation of the TFP and O&M productivity trends of OPG. Such information may prove useful to the OEB in this proceeding. Please provide a table or tables that reports OPG's year-by-year TFP and component output and OM&A and capital input quantity growth together with 21- and 15-year average annual growth rates for those variables.

c) Please provide the specific OM&A cost definitions that LEI used in its productivity study for OPG, the US investor-owned utilities, and the US utilities that do not file the FERC Form 1. LEI states on p. 29 of its productivity report that "data provided by OPG included administrative costs". Please explain the administrative costs that

are included in the OPG cost data that are used in the productivity study. How are the analogous costs treated in the U.S. data for this study?

d) The O&M cost data presented in the working papers were pasted values. Please provide the underlying data that support the OM&A expense calculations in the productivity study.

e) In Figure 10 of reference 1, LEI provides a comparison of the accounts of the FERC Form 1 to OPG's data. Aside from administrative costs, were there costs in OPG's data that did not line up with a FERC account?

f) Does the 62.6% labor cost share include pension and other benefit expenses?

g) Why did LEI use average weekly earnings (AWE) instead of a fixed weighted index (FWI) of average hourly earnings to deflate Canadian labor cost growth? Explain how this choice would be appropriate in a recessionary period.

h) What is the share of OPG in the total capacity of the hydroelectric generators that are considered in the productivity study?

Response

This response was prepared by London Economics International LLC ("LEI")

a)

i. As stated on page 22 of the TFP report, LEI used 2002 as the starting point for the TFP study as this coincided with *"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."*

   LEI also notes that contrary to the framing of the question, LEI's position regarding the appropriate timeframe for the TFP study has not changed between the 2016 proceeding and this proceeding. In LEI's 2016 TFP study, the 13-year sample period that was used was indeed the longest timeframe allowed by the availability of data at that time (i.e., 2002-2014). In the current TFP study, LEI again uses the longest timeframe allowed by the availability of data, which now happens to be 22 years (i.e., 2002-2023).

Furthermore, LEI notes that the TFP trend is consistently negative even if a shorter timeframe is used – as can be seen in Figure 34 in LEI's TFP report that shows results for a 15 or 20 year timeframe, and Figure 1 that shows TFP trends using a 22 year sample period, on pages 55 and 6, respectively. LEI reproduces those figures below for reference.

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%

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%

ii. As discussed above in response to part (i) of this IR, LEI used the longest timeframe allowed by the availability of data in both the 2016 TFP Study as well as the current study. A longer TFP timeframe would limit peer inclusion in the industry TFP study and may result in inclusion of stale drivers of productivity in the TFP analysis.

b) For the purposes of setting the base productivity component of the X factor, a TFP study of the hydroelectric generation industry as a whole is appropriate. An analysis of a single firm's total factor productivity, as suggested by this question, is not relevant and therefore LEI declines to provide the tables requested. As noted on page 7 of the TFP report:

> *"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."*

Page 9 of the TFP report goes on to explain that:

> *"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."*

c) The requested cost definitions are set out in Sections 4.2.1 and 4.2.2 (pages 29-32) of the TFP report. LEI includes relevant excerpts below.

For a comparison of the cost definitions for OPG versus US utilities that file FERC Form 1 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.*

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

As for the cost definitions for US utilities that do not file FERC Form 1 data, LEI provided the following in its TFP report:

> *For WAPA, a comprehensive set of hydro-specific data was obtained through publicly available annual reports as well as direct communications with the company. 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.*
>
> *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. 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.

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. Similarly, data for Seattle on net generation and O&M was compiled from Seattle's published annual reports. Seattle's generation facilities are entirely hydroelectric, and therefore generation and O&M data was already in the form necessary for the TFP study.

d) The O&M cost data is not sourced from one source, and therefore it is not possible to provide a comprehensive breakdown of O&M cost data as requested. In other words, the pasted values are in some cases the raw data identified in LEI's research. However, in cases where there was some assembly, we are providing additional details.

Figure 10 from the TFP report, which was included above in response to part (c) of this IR, lists the specific FERC Form 1 line items that were aggregated by LEI to calculate O&M costs for the US peers that file FERC Form 1 data – these line items include:

- Operation:
  - FF1 Account 535: Operation supervision and engineering
  - FF1 Account 537: Hydraulic expenses
  - FF1 Account 538: Electric expenses
  - FF1 Account 539: Miscellaneous hydraulic power generation expenses
  - FF1 Account 540: Rents
- Maintenance:
  - FF1 Account 541: Maintenance supervision and engineering
  - FF1 Account 542: Maintenance of structures
  - FF1 Account 543: Maintenance of reservoirs, dams and waterways
  - FF1 Account 544: Maintenance of electric plant
  - FF1 Account 545: Maintenance of miscellaneous hydraulic plant

For OPG, its OM&A data is not available in this form. Instead, LEI relied on total OM&A data as provided by OPG and shown in our working papers.

For the US peers that do not file FERC Form 1 data, we pulled the O&M data directly (i.e., without any adjustments) from the annual reports for SEPA, Chelan, and Seattle. Lastly, for WAPA, as noted above in response to part (c) of this IR, we adjusted the O&M costs stated in its annual reports by removing the costs related to one coal plant owned by WAPA, as well as transmission-related costs. Attachment 1 is an Excel file demonstrating these calculations for WAPA.

e) As noted above in response to part (d) of this IR, LEI received OPG's OM&A data in aggregate form. However, we requested that OPG provide its OM&A data in a manner consistent with the FERC Form 1 accounts listed above in response to part (d) of this IR. LEI also compared the updated data provided by OPG (i.e., for the 2015-2023 period) to the prior data received and used in LEI's 2016 TFP Study (for the 2002-2014 period) to check for anomalies and alignment across the entire study timeframe.

f) LEI understands that the labour cost share was estimated on the basis of labour costs that did include pension and other benefits. As noted on page 35 of the TFP report:

> *"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."*

According to EUCG's HPC Data Guide and Reporting Instructions, "labor" is defined as follows:[1]

- All Regular, Permanent Staff
- All temporary staff, hiring hall, part-time or casual staff (this will include long term assigned staff or longer term contract staff or where the individual looks and acts like permanent labor)
- All appropriate loadings, such as benefits, concessions, payroll taxes etc.

Overtime

g) As noted on page 36 of the TFP report, LEI used Ontario AWE (all employees) for the Canadian labour component and National GDP-IPI FDD for the Canadian non-labour component of the O&M price index to be consistent with the indices "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." In addition, as

[1] EUCG. *HPC Data Guide and Reporting Instructions.* January 31, 2024. p. 7.

noted in LEI's inflation factor analysis, the OEB currently uses AWE to track utility labour cost increases (see slides 5 and 13).

h) OPG's regulated fleet accounts for 15% of the industry capacity considered in the TFP study (based on data as of 2023). This can be calculated using the data shown in Figure 6 on page 26 of the TFP report, which is reproduced for reference below.

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.

Board Staff Interrogatory #280

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 2
Ref 2: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 2 / Confidential Working Papers
Ref 3: Exhibit D1 / Tab 1 / Schedule 2 / Table 4
Ref 4: EB-2016-0152 / Exhibit L / Tab 11.1 / Schedule 1 Staff-24

Preamble:

At Reference 1 pp. 17-19 and 39-44, London Economics International LLC (LEI) explains the monetary approach to capital cost and quantity measurement that it uses in its productivity study. LEI uses a one hoss shay (OHS) capital service flow decay assumption (aka age-efficiency profile). Assets are assumed to have a constant service flow until their retirement. Alternative specifications used in TFP evidence filed in IR proceedings include geometric decay (GD) and hyperbolic decay (HD).

Question(s):

a) LEI states on p. 19 of its productivity report that "[w]hen 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."
   i. Please confirm that statistical agencies in some countries (e.g., the United States) use HD to measure the productivity trends of individual sectors as well as the broader economy. Statistics Canada uses GD. If not confirmed please explain.
   ii. Please confirm that, whereas LEI touts the plausibility of the OHS decay pattern for many individual assets, LEI actually applies the OHS assumption to each year's total plant additions, and that these assets have varied service lives. If not confirmed, please explain.

b) LEI states on p. 19 of its productivity report that "[p]hysical deterioration is generally very limited in hydroelectric plants as the majority of the capital equipment deployed is not electrical or mechanical, but structural." Please confirm that an OHS

specification makes more sense for structures than it does for hydroelectric generation equipment. If not confirmed, please explain.

c) Please confirm that over the life cycle of many production assets (e.g., trucks) the annual cost of ownership is slowed materially by the tendency of the asset's value to depreciate for reasons that include wear and tear, obsolescence, and a shortening remaining service life. This phenomenon is not a peculiarity of cost accounting and is readily observable in asset markets (e.g., those for used airplanes and trucks). When a service price designed to mimic the price of services in competitive rental markets is matched with a capital quantity index, this real-world cost impact of depreciation can only be simulated with a decline in the capital quantity. If this statement is not confirmed, please explain.

d) Please confirm that an increasing need for maintenance and refurbishment expenditures as an asset ages can be reasonably interpreted as offsetting a decline in the service flow from the initial investment. If not confirmed, please explain.

e) Please identify three good examples of costs that tend to rise as hydroelectric assets age.

f) Please confirm that the OHS approach requires "guesstimates" of the age of retired assets whereas GD and HD do not. If not confirmed, please explain.

g) Please confirm that the OHS approach sometimes results in zero capital quantities when Handy Whitman utility construction cost indexes are used as asset price deflators. This problem has led LEI to use alternative deflators such as producer price indexes in some productivity studies. If not confirmed, please explain.

h) To the extent that LEI confirms any of the statements in parts a) to g) of this question, why is an OHS capital specification superior to a HD specification in an application to hydroelectric generation? If not confirmed, please explain.

i) Why does the OHS capital price formula 9 of the productivity report indicate that OLS_PPI is the asset price deflator?

j) Please provide full support for the statement on page 18 of LEI's productivity report that "[a] TFP study is only concerned with physical deterioration of the asset and its ability to function and produce a product or service." Is LEI saying that all legitimate TFP studies are concerned with physical deterioration? Does this mean that if two utilities are identical save that one replaces its generator after 35 years and the other after 50 years that these utilities should have identical capital quantity trends?

k) If productivity studies used to determine the productivity factors of indexes that adjust rates between rebasings should use methods that are unrelated to ratemaking, why use the generation volume to measure operating scale? Is this the ideal output measure when studying trends in hydro cost efficiency?

l) If the X factor is intended to ensure a just and reasonable rate trajectory for utilities between rate rebasings, and the industry cost trend is slowed (accelerated) by slow (rapid) growth in the rate base, why would a TFP study that ignores industry rate base trends nonetheless be optimal?

m) Please confirm that when generation capacity is used as the capital quantity, there is no consistent basis for computing the capital cost weight for the TFP index. If not confirmed, please explain. LEI has chosen an "endogenous" approach that reflects an historical valuation of utility plant. Please explain if this is the optimal weight for the capital quantity index.

n) The monetary model file in LEI's working papers is linked to three other spreadsheets which were not provided. Please provide the files "Capital_price_for_BP_March5_final.xlsx, LEI TFP Model – V041 Boston Gas and others DSM_Remove Acct 908.xlsx, and Model A – OPG industry TFP model v2024_v.02-05QC_FF1 Peers only.xlsx.

o) Why did LEI use a single Handy Whitman utility construction cost index for hydroelectric power generation when these indexes are available for six regions of the United States and appropriate regional indexes could have been applied.

p) LEI states on p. 59 of its productivity report that "OPG's average service life for the whole asset base was estimated to be 82 years." For purposes of calculating retirement quantities, however, LEI states on p. 44 of the report that it assumed a 43-year average service life "which is based on OPG's average book-value-prorated asset life for the equipment class of assets." How can LEI be sure that the data for some sampled utilities don't include the retirement of structures?

q) Please provide additional details on the calculation of the 2000 benchmark year plant addition value for OPG. Was it gross or net of depreciation? Was it the value at the beginning of the year or end of year? What assets were included in this value (e.g., was hydro common plant included)?

r) PEG compared the in-service capital additions for OPG that LEI provided in its working papers for the monetary approach to TFP measurement and found that they were not consistent with data OPG provided in References 3 and 4. While most of these differences are minor, the 2016 capital additions value in the LEI working papers is about 33% higher than the amount OPG reports in Reference 3.

Please provide details on the plant additions LEI relied upon (e.g., were hydro common plant additions included?) and explain the differences in data between these sources.

Response

Parts a) to p) of this response were prepared by London Economics International LLC ("LEI")

a)

i. Confirmed.

ii. LEI can confirm that the application of OHS is to total plant additions (including new investments). The OHS depreciation profile is appropriate for the hydroelectric generation industry, because as noted on page 19 of LEI's TFP report:

> *"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). 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. … 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"*

b) LEI believes the OHS specification is appropriate for a hydroelectric plant and its ability to produce the specified output (energy). The metrics used in LEI's physical and monetary TFP studies were chosen to capture the physical deterioration of each hydroelectric plant as a whole.

For the physical TFP study, physical deterioration is captured through our use of the annual Maximum Continuous Rating ("MCR") value of each plant. MCR values can change from year to year based on upkeep and upgrades and/or physical deterioration of the assets. As noted on page 12 of the TFP report:

> "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."

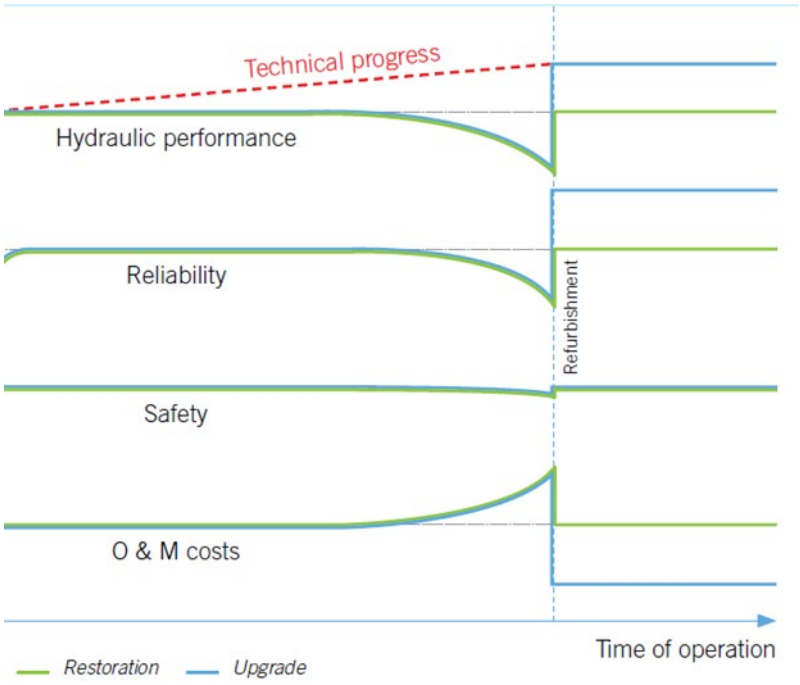
For the monetary TFP study, physical deterioration is captured through our use of capital expenditure and O&M data, which reflects the costs incurred to maintain the physical capability of each power plant.

c) In the context of its work, LEI cannot confirm this statement. LEI's analysis was not focused on used airplanes or trucks. We tailored our TFP analysis to be suitable for the hydroelectric generation industry.

d) LEI can confirm that there is an increased need for maintenance expenditure for aging power plants, as described further below. To the extent that the necessary expenditure is made to maintain the productive capability of the power plant, then we should not expect a decline in the services that the asset can provide.

Hydroelectric generation assets are maintained through both operating and capital expenditures to ensure that the plant's ability to generate energy (output) is maintained. According to the Hydro Equipment Association ("HEA"), the chart below illustrates the trend in spending (labeled as O&M costs) required to maintain hydro equipment and *"to ensure the plant's availability, reliability and safety"*[1] remain on par with initial design as the asset ages.[2] As seen in the chart below, reliability is fairly constant over time (commonly, a decline in reliability is expected at the end of life which is known as the "bathtub curve"[3]). At that point of decline, intervention is undertaken through a variety of maintenance programs to restore reliability. Some may involve refurbishment or replacement of electrical or mechanical equipment; if such equipment is replaced, there may be further opportunity to increase efficiency and production.

[1] HEA. Global Technology Roadmap. 2015. P. 30.
[2] There may be times when an operator chooses to not maintain an asset to their original design – but those decisions arise as a result of economic considerations and typically only towards the end of service life.
[3] O&M costs for hydroelectric generation assets follow a 'bathtub curve' in which the failure rate of equipment (and, therefore, the need to make repairs and additional maintenance/warranty work) is highest at the beginning of an asset's life, then stable once common start-up issues are resolved and steady state operations begin, and increase towards the end of an asset's useful life. (Source: EB-2016-0152, Exhibit L, Tab 11.1, Board Staff Interrogatory #226 (c))



e) As hydroelectric assets age, costs that typically increase include:
   1. Maintenance on turbine components that are susceptible to cavitation and erosion, and on transformers requiring gasket, bushing and oil replacement.
   2. Concrete civil work including mitigation for alkali-aggregate reaction (AAR), freeze thaw cycles and general cracking and spalling.
   3. Enhanced condition monitoring like non destructive examination (NDE), increased thermography, and ROV/dive inspections.

f) LEI did not use a GD or HD approach. LEI did use a OHS approach for representing the physical depreciation of the capital and its impact on productivity. LEI objects to the term "guesstimates". LEI used an informed assumption regarding the service life of any retired assets. Specifically, as noted on page 44 of the TFP report:

> *"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. … 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. 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."*

g) LEI used the Handy Whitman Cost Index ("HWI") for Hydraulic Production Plant and did not experience a problem with zero capital quantities in this TFP study.

h) For all of the reasons discussed above in response to parts (a) to (g) of this IR, LEI believes that the OHS capital specification for physical deprecation of capital is appropriate for hydroelectric generation in an industry TFP study.

i) As discussed in response to Ex. L-A1-Staff-277 above, there is a typographical error in Appendix B of the TFP report, specifically with regards to the asset price deflator shown in the implicit rental price formula. LEI used HWI for Hydraulic Production Plant as the capital cost index to convert all retirements and additions into constant dollar terms (2002 dollars). This is confirmed on page 40 of LEI's TFP report, which reads:

> *"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") for Hydraulic Production Plant to represent all retirements and additions in 2002 dollars, which reflects the start year of the TFP study timeframe."*

The typographical error appearing in Appendix B of the TFP report does not in any way impact LEI's TFP analysis, workpapers, or the results.

j) LEI's statement on page 18 is related to the specific nature and application of the TFP study in this instance – which is to calibrate the X factor for incentive ratemaking purposes.

k) In response to both questions, LEI's reasoning for using generation as the output measure in the TFP study was provided above in response to part (a) of IR L-A1-Staff-278.

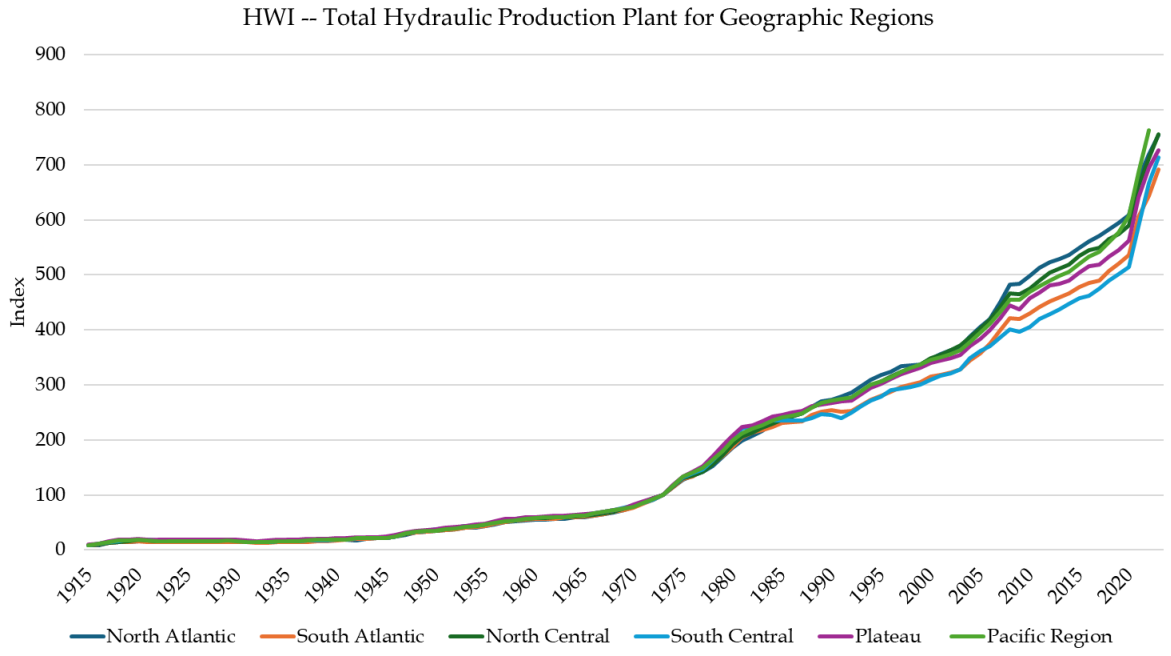
l) LEI does not understand this question. LEI's analysis is capturing investment trends over time (e.g., as implied by "changes in rate base" in the wording of the question), as reflected in the use of annual capital expenditures and retirements under the monetary approach, and by reference to the changes in the annual MCR value under the physical approach.

m) Under a physical approach to measuring capital input quantity, LEI does calculate a weight for capital. This weight is based on an endogenous approach, which reflects the residual value of capital given the market value of the output energy produced by that capital. LEI draws an exception and is unclear on what the question is intending when equating the endogenous approach to the "historical valuation of utility plant" and further reference to "optimal weight".

n) These links are not relevant to the TFP analysis and can be ignored; they are vestiges of data links and transformation that have no bearing on the results of the TFP study:

- "Capital_price_for_BP_March5_final.xlsx" contains data from the TFP monetary model working paper that was used for LEI's inflation factor analysis
- "LEI TFP Model – V041 Boston Gas and others DSM_Remove Acct 908.xlsx" links to an unused Base_Year data label
- "Model A – OPG industry TFP model v2024_v.02-05QC_FF1 Peers only.xlsx" links to a VLOOKUP feature that is not used in the monetary model

o) As demonstrated in the chart below, the Handy Whitman Cost Index for Hydraulic Production Plant follows a similar trend across the regions. As such, LEI does not expect that adding the additional specification of region-specific HWIs will materially change the TFP results.



p) Retirement of structures is rare and typically only happens when an entire plant is decommissioned. Within the industry sample used in LEI's TFP study, we did not identify any plants that were producing energy and were decommissioned during the span of the study period (2002-2023).

q) The year 2000 value of $6.7B is the fixed asset value at the beginning of the year, gross of depreciation. Hydro common assets are excluded.

r) OPG is unclear as to the information being referenced in Reference 4, as "EB-2016-0152 / Exhibit L / Tab 11.1 / Schedule 1 Staff-24" is not a valid interrogatory number. The remainder of this response compares the working papers to Reference 3.

The 2016 variance is primarily due to the Niagara Tunnel Reallowance of $21.6M reflecting the OEB's decision in EB-2014-0369 (refer to Ex. H1-1-1, Section 5.13). This amount is not included in Ex. D1-1-2, Table 4 as it relates to project work completed in prior years. This amount is instead reflected as a direct adjustment to rate base in 2016, as shown at Ex. B2-3-1, Table 1, line 1, col. (c). Hydro Common assets are excluded from the plant additions provided to LEI.

Given the magnitude of the discrepancy, LEI does not expect that there would be any material impact on the TFP results.

Board Staff Interrogatory #281

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 2

Preamble:

London Economics International LLC (LEI) also calculates the Total Factor Productivity (TFP) trend using a physical approach to capital quantity measurement. The generation capacity rating is used for this purpose.

Question(s):

a) Please confirm that this approach to measuring capital quantity trends does not consider trends in the capital cost incurred to make capacity available. If not confirmed, please explain.

b) Please confirm that, using LEI's physical approach to measuring capital quantity trends, OPG's costly Niagara Tunnel project had no impact on the Company's measured capital quantity trend.

c) Is the Maximum Continuous Rating consistent with either nameplate or operating capacity? What data series was used for the U.S. utilities?

d) Please explain how the reported fact that the average annual growth rates of monetary and physical approaches to measuring the capital quantity trend differed by only 13 basis points between 2002 and 2023 squares with the fact that these two approaches produced much larger reported differences in TFP growth in figures 33 and 34.

Response

This response was prepared by London Economics International LLC ("LEI")

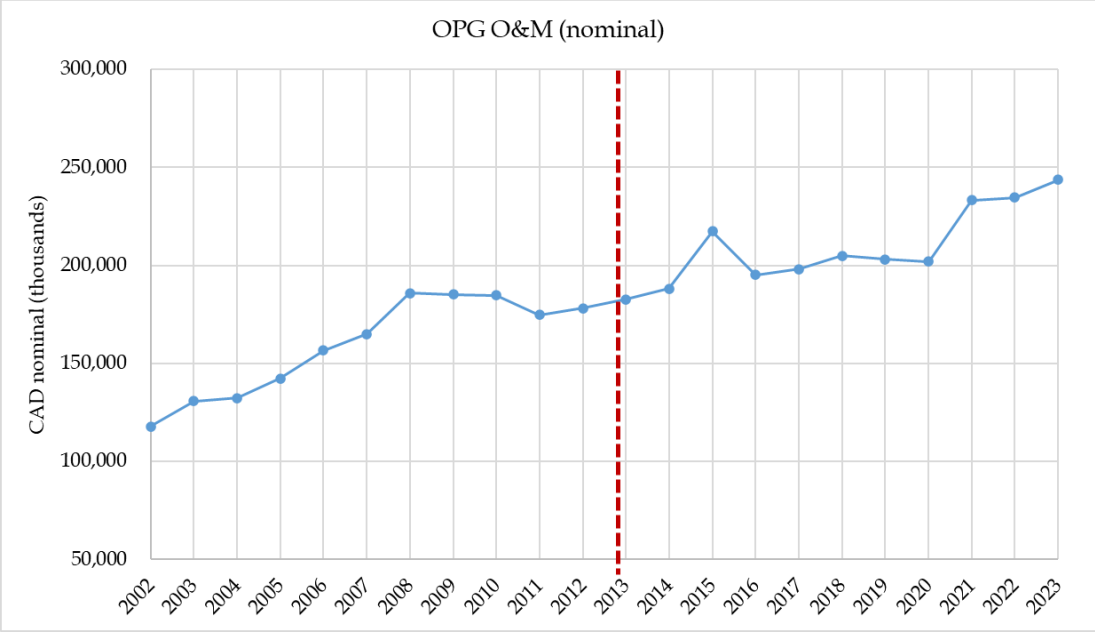
a) Under the physical approach, the change in capital quantity is measured based on the change in the annual Maximum Continuous Rating ("MCR") value of each plant as a proxy for capital related spending. As noted on page 12 of the TFP report:

> *"incremental capital investment is implicitly captured in the MCR measure, as maintaining or enhancing installed*

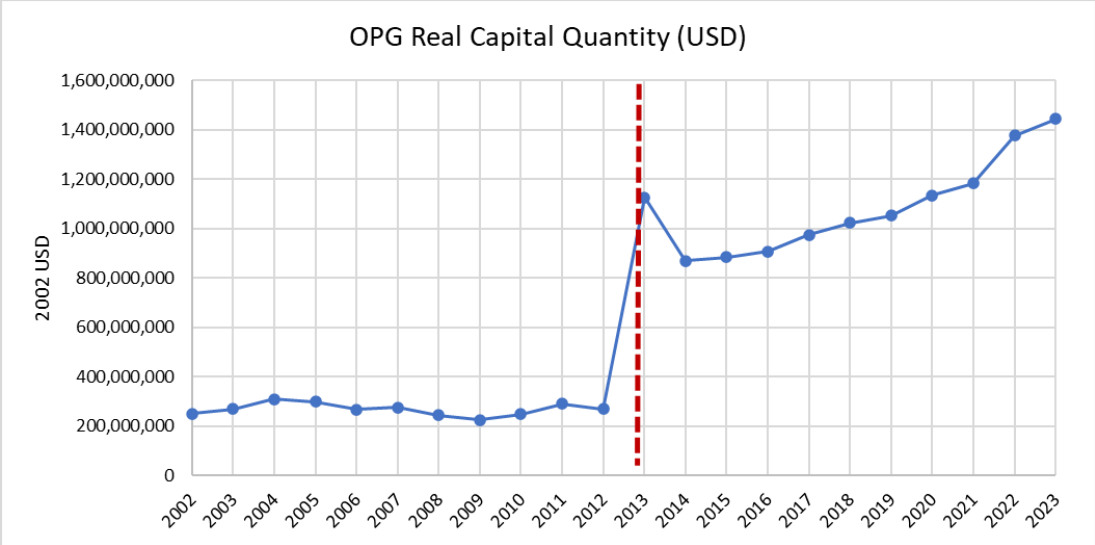
capacity over time requires ongoing investment. Indeed, LEI has observed that some of the hydroelectric plants included in the industry sample for the TFP study increased their MCR over time. If the generator did not undertake such investments to sustain the productive capacity of its hydroelectric assets, a decline in MCR would be observed."

b) The Niagara Tunnel Project ("NTP") expanded the volume of water flows at OPG's Sir Adam Beck generating stations 1 and 2.[1] However, the MCR values for these facilities did not change when the project was completed in 2013.

Nonetheless, the increase in inputs required for NTP was captured in other ways in LEI's TFP analysis, including as reflected in OPG's nominal O&M and real capital stock, which are shown in the charts below. The data can be found in rows J5:J26 of the TFP_dataset tab in the physical TFP working paper, and rows O335:O356 of the Capital_Cost tab in the monetary TFP working paper, respectively. LEI's workpapers are filed in Ex. L-A1-Staff-002.



[1] Ontario Power Generation. EB-2013-0321 Exhibit D1 Tab 2 Schedule 1. Page 2. September 27, 2013.



c) As stated above in response to part (a) of this IR, MCR is not a static capacity number – it changes over time.

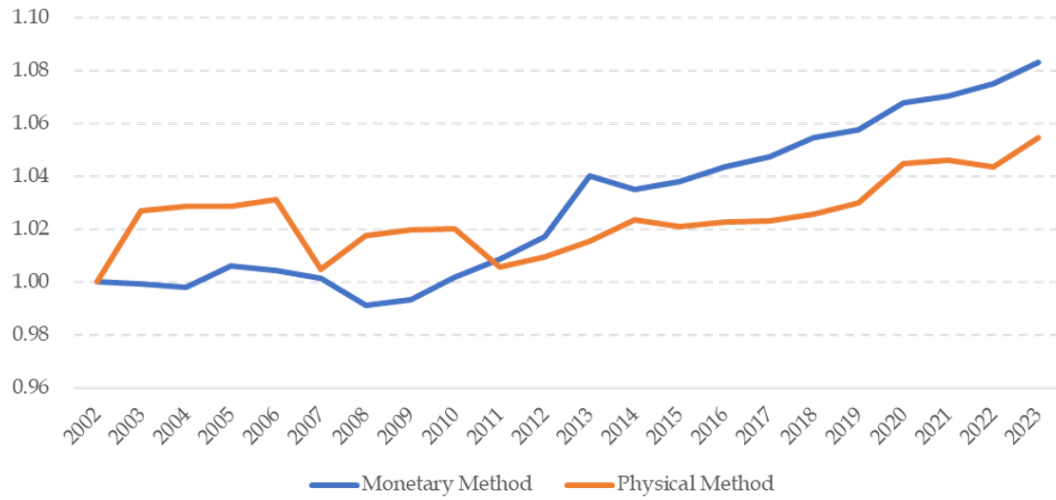
For US utilities that file FERC Form 1 data, LEI used the "Gen name plate rating in MW" (line 5) from FERC Form 1, which is defined as the demonstrated maximum generating nameplate ratings of power plants. This metric indicates the productive capability of the asset without exceeding design thermal limits. It explicitly reflects the performance of the capital equipment because utilities routinely test their assets' performance to develop these numbers.

For US utilities that do not file FERC Form 1 data, we used the best available definition in each entities' annual report, which also vary over time based on the reported data.

d) LEI understands that the "13 basis points" mentioned in the question refers to Figure 32 of the TFP report and the surrounding text, which is reproduced for reference below.

> *"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. … 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."*

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



As noted in the quote above, these trends were reported using the average method of estimating the growth rates.

However, the question also refers to Figure 33 of the TFP report, reproduced below, which shows LEI's TFP results under the physical and monetary approaches, in this case using the 'trend regression' method of estimating the growth rates.

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%

These two methods can produce different results because the average method is more sensitive to endpoint values, whereas the trend regression method reduces the weight attached to the first and last years of the study period (as discussed on pages 20-21 of LEI's TFP study).

Accordingly, part of the difference observed between the capital input growth comparison in Figure 32 and the TFP results in Figure 33 reflects differences in the growth rate calculation methodology (average versus trend regression).

Board Staff Interrogatory #282

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 3 / Confidential Working Papers
Ref 2: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 3 / pp. 18-19
Ref 3: Exhibit A1 / Tab 11 / Schedule 1 / p. 3

Preamble:

Using data from 13 utilities for the 2020-2023 period, London Economics International LLC (LEI) developed econometric models of the OM&A expenses and OM&A plus "sustaining capital" expenses incurred at various hydroelectric generating stations of thirteen utilities.

LEI added firm-specific dummy variables to the model for each company save OPG. The average of the parameter estimates for these variables was then used to benchmark OPG's performance over the four-year period. OM&A costs were reported to be 40% below the norm while OM&A + sustaining capex costs were 15% lower. Based on these results, LEI recommends a stretch factor in the range from zero to 0.15%.

At Reference 3, OPG indicates that the LEI benchmarking study meets the filing requirement for a total cost benchmarking study that the Company agreed to in its last payment amounts proceeding.

Question(s):

a) The working papers provided contain trend indexes including an Employment Cost Index (ECI) and Gross Domestic Product Price Index (GDPPI). The ECI indexes show values for different regions of the US. Because the values for each index are 1.00 in 2013, it appears that the price levels for each company in each region of a country were assumed to be the same. Other than a currency adjustment between the US and Canada, were any other adjustments made to address differences within and between regions?

b) In Reference 2, the report states, "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."

i. Please expand on LEI's reasons for using only four years of data for the entire model, instead of alternatives such as using a longer sample period but extracting the most recent four years of cost performance? Was the sample period shortened in order to use OPG's dummy variable parameter estimate to benchmark the Company?
ii. What was the longest sample period possible using the Electric Utility Cost Group (EUCG) data?
iii. Does LEI believe that business conditions were typical during the years 2020-2021, which represent half of the sample period? Please explain why or why not.

c) Please confirm that LEI's approach could not measure the trend in OPG's cost efficiency even if the sample period for model estimation was longer.

d) Why didn't LEI use its econometric models to benchmark OPG's proposed cost during the plan? Does LEI's chosen methodology complicate such an analysis?

e) Please confirm that benchmarking of forecasted cost is common in proceedings to approve Custom IR plans. One reason is that annual benchmarking is not expected during Custom IR plans to reset the stretch factor, as has been done for many of Ontario's electricity distributors since 3rd Generation IRM was implemented in 2009.

f) In Reference 2, LEI refers to "the specified economic model" and the addition of company fixed effects. However, the Applicants do not state the actual estimation procedure used.
i. Please confirm whether the model is estimated via standard Ordinary Least Squares (OLS). If not confirmed, please identify the specific estimation procedure used.
ii. The limited Stata output provided suggests the Applicants did not use robust estimation techniques for the OLS coefficient standard errors. Please confirm, or if not confirmed, please provide the name of the technique used.

g) LEI states on page 7 of its benchmarking report that "the fixed effect in this benchmarking study measures the impact on the cost of a generating plant associated with ownership." Please confirm that the parameter on the fixed effects variable also captures the average cost impact of all factors unique to a company that are not properly reflected in the other variables. Suppose for example, that differences in price levels are not properly reflected in the input price data used in the estimation. Please confirm that differences in price levels are then reflected in the estimated fixed effects parameters. The Applicants state that they used "observations for 253 plants owned/operated by 13 hydroelectric power plant operators, including OPG."

i. Please provide the share of the Applicants' observations in the total observations in the model.
ii. If this percentage is greater than 20% (this is implied as the Applicants operate 54 plants), please describe the consideration given to this issue. Does LEI have concerns about assigning quintile rankings if OPG makes up more than 1/5 of the data?
iii. Please confirm that LEI's benchmarking results pertain to the average scores for its various hydro stations and are not size-weighted.
iv. Insofar as the benchmarking results were not size-weighted and a major capex category was excluded from the benchmarking, is it accurate to call this model (much less the OM&A model) a total cost benchmarking study, as LEI does in its report, and as required by the approved settlement in EB-2020-0290?
v. Since the OM&A plus sustaining capex study is closest to total cost benchmarking, why doesn't LEI recommend a 0.15% stretch factor rather than a [0, 0.15%] range?

Response

This response was prepared by London Economics International LLC ("LEI")

a) The values for each index are 1.00 in 2013 because 2013 is used as the anchor year for that data in the LEI benchmarking study. However, over the study timeframe (2020-2023), the index values do vary. Indeed, the labour price indices vary by year, region, and country (US BLS' ECI is used for the US peers, Statistics Canada's AWE is used for the Canadian peers). The non-labour price indices vary by year and country (US BEA's GDPPI is used for the US peers, Statistics Canada's GDP IPI is used for the Canadian peers).

b)

i. LEI's reasoning for using a four-year study period is discussed on page 18 of the benchmarking report:

> *"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."*

Furthermore, a materially longer study period would have reduced the number of peers and changed the makeup of the peer group that we would have been able to obtain from the EUCG dataset, while ensuring a consistent representation of power plants of varying sizes, vintages, and equipment.

With regards to the second part of the question – the use of a fixed effects model, which creates a dummy variable for each reporting entity other than OPG (i.e., OPG's fixed effect is equal to zero) did not alter the study timeframe that LEI employed. Therefore, LEI did not need to shorten the sample period "in order to use OPG's dummy variable parameter estimate" as suggested by the question.

ii. The EUCG dataset provided to LEI goes back to 2006. However, as noted above in response to part (i) of this IR, using a study period longer than four years would have reduced the number of peers and interfered with LEI's ability to present an econometric analysis that uses a strongly balanced panel.

iii. LEI acknowledges that during the 2020-2021 period the COVID-19 pandemic affected broader economic and human activity around the world. Initially, LEI conceptually considered a timeframe that would exclude these years, but it would have required either: (a) restricting the timeframe, which would compromise the study, or (b) adding older data, which would also be suboptimal relative to the goal of measuring current total cost performance. LEI therefore proceeded to include the 2020 and 2021 data. LEI included a time trend variable to monitor for time-based considerations. The time-trend variable in both the OM&A model and the OM&A + SC model did not have a statistically significant impact on expected costs over the study timeframe, as indicated by the p-values. These results can be interpreted as not statistically different from the assumption that the impact of the passage of time on costs was zero over the study period, 2020 to 2023.

c) LEI interprets "trend … in cost efficiency" in the question as referring to trends that are captured in a TFP analysis. And indeed, there are econometric approaches that *can* establish the trend in cost efficiency over time on either on a total cost basis (a TFP analysis) or on a partial cost basis (a partial factor productivity, or PFP, analysis) – this can be done using stochastic frontier analysis ("SFA"). However,

that was not the intent of the LEI benchmarking analysis – as explained on page 18 of the benchmarking report:

> *"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."*

d) This was outside of LEI's scope and workplan for the total cost benchmarking analysis. As explained on page 9 of the benchmarking report, the goal of LEI's benchmarking analysis was to analyze the relative efficiency of the regulated entity (OPG) compared to other peers in the hydroelectric generation industry in order to recommend a stretch factor. LEI believes that use of recent actual data, rather than forecasts, is preferred to address this objective. Specifically, *"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.****"* [bold emphasis added]

e) While LEI understands that this is the approach used in some recent Custom IR plans before the OEB, we have not been involved in these proceedings. We cannot confirm what is "common."

f)

i. LEI can confirm that we used OLS as the estimation technique.

ii. LEI carried out the regression analysis for both the OM&A model and the OM&A + SC model in Stata using the "reg" command, as reflected in the "Stata Commands - OM&A Model.do" and "Stata Commands - OM&A+SC Model.do" (Attachments 1 and 2 to Ex. L-A1-Staff-283, respectively).

g) The fixed effects specification captures the impact of factors at the ownership level that are not otherwise included in the other explanatory variables. As noted on page 19 of the benchmarking report:

> *"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."*

i. OPG was the owner of 50 plants of the 253 plant observations annually, which is 20%.

ii. As noted above in response to part (i) of this IR, OPG accounted for 20% of the 253 plant observations annually (i.e., 50 plants). Nonetheless, the quintile rankings are independent of the number of observations. This is because the relative efficiency quintile rankings presented in LEI's benchmarking report are based on owner-level fixed effect coefficients, rather than individual plant-level results. Accordingly, the number of plants associated with a given owner does not give rise to concerns in the context of the quintile rankings.

iii. Confirmed. It would not make sense to weight the benchmarking results as we already controlled for the scale of operations by using plant size (gross capacity in MW) as an independent variable. As noted on page 20 of the benchmarking report: "Plant size (gross capacity in MW) was positively correlated with higher total costs and reflects economies of scale."

iv. LEI's OM&A + SC model includes operations, maintenance, and administration expenditures, including non-reoccurring project-related O&M expenses, as well as the expenditures related to a subset of capital spending (sustaining capital). LEI believes that this qualifies the study as a total cost study. LEI's logic for exclusion of certain non-recurring capex is explained on page 6 of the LEI benchmarking report.

v. LEI's recommended stretch factor range between 0% to 0.15% corresponds to the separate benchmarking results of the OM&A model and the OM&A + SC model and OEB's practice as it relates to cohorts for electric distribution utilities. This is further discussed on page 25 of the LEI benchmarking report. As a further point, LEI understands that OPG has proposed a 0.15% stretch factor in its application.

Board Staff Interrogatory #284

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 3 / p. 22 / Fig. 7
Ref 2: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 3 / p. 20
Ref 3: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 3 / Confidential Working Papers

Preamble:

At Reference 1, the Applicants provide their econometric results for OM&A expenses.

At Reference 2, London Economics International LLC (LEI), referring to the precision of the model coefficients, says “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.”

Question(s):

a) Please confirm that the negative parameter on the OM&A price implies that as price increases, cost decreases. If not confirmed, please explain why. If confirmed, why is this result reasonable?

b) Please provide an interpretation of this coefficient’s magnitude.

c) Please confirm that the OM&A and capital price indexes in LEI’s econometric cost models are not logged whereas the cost is logged. If not confirmed, please explain why. If confirmed, why is this approach preferable to logging both variables?

d) The trend parameter in the OM&A cost model is reported as -0.02. Please confirm that this implies that OM&A cost trends downward with the passage of time. Can this be interpreted as approximately 2% per year?

e) Does this result support the idea that expecting future cost reductions is reasonable and that OM&A productivity growth should be positive?

f) Please elaborate on the scope of the OM&A costs included in the benchmarking study to provide a better understanding of what costs are being benchmarked.
   i. Which FERC accounts are included?
   ii. What is meant by “administrative”?
   iii. Are pensions and benefits included?

iv. Are payroll taxes included?
v. Do the reported OM&A costs on a plant level sum to the amounts reported on the Form 1? If not, what accounts for any differences?

Response

This response was prepared by London Economics International LLC ("LEI")

a) For a statistically significant independent variable, a negative coefficient implies an inverse relationship with the dependent variable. However, as noted on page 21 of the benchmarking report, the OM&A price variable was not statistically significant in both the OM&A model and the OM&A + SC model.

b) As noted above in response to part (a) of this IR, the OM&A price variable in LEI's analysis was not statistically significant as indicated by the p-values – this was the case in both the OM&A model and the OM&A + SC model. As noted on page 21 of LEI's benchmarking report: "In other words, the results were not statistically different from the assumption that impacts of prices on costs were zero."

c) LEI can confirm that the OM&A and capital price indices were not logged, as indicated in Figure 3 of the benchmarking report. LEI applied natural logarithms to certain variables to support the interpretability of their coefficients. However, in the case of the OM&A and capital price indices, these are expressed in unit-less levels, such that a one-unit change can readily be interpreted in terms of relative price movements, and thus these indices do not necessarily need to be logged.

d) The time or trend parameter in both the OM&A model and the OM&A + SC model did not have a statistically significant impact on expected costs over the study timeframe, as indicated by the p-values. These results can be interpreted as not statistically different from the assumption that the impact of the passage of time on costs were zero over the study period.

e) No. This is a specific result for a specific model that studied a four-year period from 2020 through 2023. This result should not be interpreted as necessarily applying to future productivity trends.

f) LEI can confirm that pensions and benefits (iii), and payroll taxes (iv) are included, as indicated in response to Ex. L-A1-Staff-279 part (f). We cannot confirm the other items listed above because we did not do this comparison – we received aggregated OM&A data from EUCG that did not include a breakdown.

Board Staff Interrogatory #286

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 3 / p. 15
Ref 2: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 3 / p. 17 / Fig. 5

Preamble:

At Reference 1, London Economics International LLC (LEI) discusses variable selection for the econometric benchmarking models.

At Reference 2, the Figure lists various data available from the Electric Utility Cost Group (EUCG).

Question(s):

a) In Reference 1, the report states, "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."
   i. What were these tested and rejected variables and the reasons for their rejection?
   ii. Was the generation volume tested as an output variable? If so, was it found to have an insignificant cost impact in the two cost models?
   iii. Did LEI consider variables based on each of the eight kinds of plant profile data listed at Reference 2 and find none of them to be suitable?

Response

This response was prepared by London Economics International LLC ("LEI")

a)

i. The EUCG dataset provided to LEI included many descriptive data (see list below), some of which could be candidates for independent (explanatory) variables:

- Year
- Water Spilled
- Gross Actual Generation
- Net Actual Generation
- Remote Units
- Condense Units
- Enclosed Powerhouse
- Full Capacity

- Period Hours
- Service Hours
- Reserve Shutdown Hours
- Condensing Hours
- Pumping Hours
- Forced Outage Hours
- Maintenance Outage Hours
- Planned Outage Hours
- Region Code
- State
- River
- Plant Type
- Dam Type
- Operating Purpose
- Production Mode
- Number Units
- Active Units
- AGC Units
- Gross Capacity
- Net Capacity
- DO enhancement
- Temperature restrictions
- Flow restrictions
- Fish habitat improvement
- Oil containment
- Flood control
- Recreational constraints
- Plant Project, Run of River vs Storage
- Date of Commercial Operation
- Status
- Predominate Turbine Runner Type
- Plant Design Head
- Unstaffed or Staffed Control Room
- No. of Plants per Control Room
- No. of Units per Control Room
- MW per Control Room

We tested various combinations of some of these variables, but generally found that they were not statistically significant for the study timeframe and group of power plants, and thus excluded them from the analysis.

ii. Please see response to part a)i of this IR above.

iii. No. LEI understands the “eight kinds of plant profile” mentioned in Reference 2 refer to the categories listed above in Ex. L-A1-Staff-285 part (c). These eight plant profiles are not explicitly identified in the EUCG dataset and therefore were not considered in LEI’s analysis.

Board Staff Interrogatory #287

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 3 / pp. 13-16

Preamble:

At Reference 1, the Applicants discuss the one scale measure and two "business condition" independent variables ultimately selected for the econometric benchmarking models.

Question(s):

a) In Reference 1, London Economics International LLC (LEI) selects a binary variable for operating over/under 2 units per plant site and state that approximately 50% of plants in the sample operate only 1 or 2 active units. LEI explains that the model parameter for this variable shows that plants with 1-2 units have lower cost, implying there are no economies of scale to be found for plants with more than 2 units.
   i. Please explain why a binary variable was preferred over modeling the actual number of units per plant.
   ii. If it is not possible to provide the relevant data to allow PEG to undertake an analysis, please provide the total number of plants which have a value of 1 for this variable and a simple table with the percentage of plant observations with a value of 1 for each of the 13 plant operators (using the alphabetic identifiers).
   iii. Can the Applicants provide insight into what factors determine whether a plant requires a staffed control room?

Response

Parts a)i and a)ii to this response were prepared by London Economics International LLC ("LEI").

a)
   i. LEI adopted a parsimonious specification by using a single dummy variable to represent the number of active units, instead of including multiple dummy variables for incremental unit thresholds. This approach avoids an unnecessary reduction in degrees of freedom associated with additional parameters. Furthermore, as stated on page 14 of LEI's benchmarking report, "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." LEI also chose not to use the actual number of units as a continuous variable, as this would have reduced the interpretability of the results relative to using a single dummy variable.

ii. The number of plants which have a value of 1 for this variable is 124. The table below provides an overview of the percentage of plant observations with a value of 1 for each of the 13 plant operators:

Plant operator	Percentage of plant observations with a value of 1
A	38%
B	50%
C	85%
D	29%
E	17%
F	11%
H	58%
I	0%
J	42%
K	67%
L	63%
M	67%
N	0%

iii. As described in Ex. A1-4-2, Section 2.0, OPG operates four regional hydroelectric control centres that are geographically located to support regulated and contracted hydroelectric operations. The locations are determined based on business need and are situated in host communities, rather than factors specific to any individual generating station.

Board Staff Interrogatory #288

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 3 / p. 6

Preamble:

At Reference 1, London Economics International LLC (LEI) describes the capital investments included and excluded from the OM&A + SC model.

Question(s):

a) In Reference 1, the report states that, ". . . 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."
   i. Did LEI include the changes to capacity associated with any "improvements and additions to plant generation capacity" in the Gross Capacity (MW) explanatory variable? Please explain and comment on any implications for the model and its results.
   ii. Did LEI attempt to separate OM&A directly associated with the "improvements and additions to plant generation capacity" during the sample period? Please explain and comment on any implications for the model and its results.
   iii. Why did LEI use the US gross domestic product price index and the Canadian GDP implicit price index for final domestic demand as input price indexes for capex instead of the available regional Handy Whitman Construction Cost Indexes for Hydroelectric Generation?

Response

This response was prepared by London Economics International LLC ("LEI")

a)
   i. LEI used the capacity as reported in the EUCG database in the econometric model; no adjustments were made to the data.

ii. The EUCG dataset used by LEI did not report OM&A data in this way, so LEI did not attempt to make any adjustments or otherwise "separate OM&A directly associated with the 'improvements and additions to plant generation capacity'."

iii. As indicated on pages 13-14 of LEI's benchmarking report:

> *"**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 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"*

Within a cross-sectional panel dataset such as the dataset used in LEI's benchmarking analysis, sufficient variability in the data is key to a robust model. Therefore, LEI chose to use US GDP-PI and Canadian GDP-IPI FDD as proxy measures for the price of capital – this allowed for consistent measurement across both US and Canadian entities, while also allowing for differentiation at the national level. Handy Whitman indices would not allow for the same differentiation between US and Canada.

In the TFP study, the GDP-IPI data from Statistics Canada was not sufficient (in terms of length of data available) and therefore, in that case, LEI relied on the Handy Whitman index for deflation of capital cost.

Board Staff Interrogatory #289

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / pp. 1-26

Preamble:

At Reference 1, the Applicants discuss their proposed Custom IR plan for prescribed hydroelectric facilities.

Question(s):

a) On page 15 of Reference 1, OPG characterizes its proposed 0% productivity factor as embodying "an incremental 0.40% to 1.01% stretch factor relative to observed TFP performance."
   i. Please confirm that, apart from the modest stretch factor that OPG is proposing, OPG will be compensated for the extent that I-X revenue escalation falls short of the Company's forecasted capital revenue requirement. If not confirmed, please explain why.
   ii. Please provide evidence supporting the notion that the I-X formula would entail any incremental stretch factor in an application to the Company's OM&A expenses.

b) Please explain why the Capacity Refurbishment Variance Account (CRVA) is an insufficient basis for providing supplemental funding for CRVA-eligible investments.

c) OPG states on page 17 of Reference 1 that the "The C-factor allows OPG to maintain the efficiency incentives of the price cap approach use to set base hydroelectric payment amounts while also recovering incremental capital-related revenue requirement associated with the significant investments required." Are all efficiency incentives of the price cap approach maintained or just the incentive yielded by the proposed 0.15% stretch factor?

Response

a) i. Not confirmed. Refer to Ex. L-A1-VECC-001, part b).

ii. The referenced statement refers to the fact that, to the extent that the North American hydroelectric generation industry is experiencing negative total factor productivity growth, such declining productivity is not accounted for in the I-X

adjustment proposed by OPG, given that the company has accepted a 0% productivity adjustment.

b) The purpose of the C-factor is to recover incremental revenue each year in order to support substantial capital investments in the regulated hydroelectric facilities over the forecast period, beyond the amount that would be recovered through the I-X adjustment alone. This funding is not limited to CRVA-eligible projects.

In addition, while the CRVA captures the revenue requirement impacts of CRVA-eligible projects, it does not allow for the timely recovery of such costs. As discussed at Ex. H1-1-1, pp. 18-20, the proposed CRVA methodology requires the balance to be evaluated on a cumulative basis over the IR period. This means that the balance recorded in the account cannot be evaluated until an application filed after the conclusion of the period, with recovery beginning subsequent to such an application. For example, an application to dispose of deferral and variance account balances could be filed in 2033 requesting disposition to begin in 2034. This timeline demonstrates that the recovery of costs incurred using the CRVA is delayed as compared to the use of the C-factor.

c) Refer to Ex. L-A1-EP-002.

Board Staff Interrogatory #290

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 3 / p. 5

Preamble:

At Reference 1, London Economics International LLC (LEI) describes that the Total Cost Benchmarking study relies on a peer group of 13 operators, of which only one other Canadian entity is included.

Question(s):

a) Please discuss why LEI and OPG considers this sample representative of the Canadian hydroelectric operating environment.

b) Please confirm whether OPG or LEI attempted to include additional Canadian hydroelectric operators and, if so, why they were not included; If not confirmed, please explain the reason.

c) Given differences in environmental regulation, labour structure, water rental frameworks, and capital expenditure requirements between OPG and U.S. operators, please describe what adjustments, if any, LEI made to account for these structural differences.

d) Please provide any sensitivity analysis LEI conducted comparing OPG only to the Canadian peer.

Response

This response was prepared by London Economics International LLC ("LEI")

a) LEI did not assert that the benchmarking peer group was representative of the entire Canadian hydroelectric operating environment. Nonetheless, LEI acknowledges that inclusion of one Canadian peer entity in addition to OPG is better than having no other Canadian peers. Please also see LEI's response to part (b) of this IR below.

b) With regards to the benchmarking study, LEI relied on the EUCG dataset for the reasons described in response to Ex. L-A1-Staff-283 part (a). As set out on page 5 of the benchmarking report:

> *"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."*

LEI could not add additional Canadian hydroelectric operators to the benchmarking analysis using alternative data sources, as this would have compromised the comparability of the benchmarking data, which was why we chose to solely use the EUCG dataset to begin with.

As for the TFP study, LEI did attempt to include Canadian peers in the industry sample. As documented on page 23 of LEI's TFP report:

> *"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."*

As further described in Section 4.3 of the TFP report:

> *"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 to the lack of necessary data for*

> *the TFP study, these Canadian peers were ultimately excluded from the final peer group."*

c) As noted on pages 17-18 of the benchmarking report:

> *"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 … 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."*

In fact, as explained in EUCG's Annual Cost and Performance Report: "OMA is the closest measure of total common costs across utilities because regulatory and environmental expenses can vary significantly by jurisdiction and geography."

Any additional differences in cost drivers that are tied to the jurisdictions that the owners operate in could be captured in the fixed effects, which are at the reporting entity level. LEI's benchmarking peer group includes entities across various provincial and state jurisdictions and therefore the fixed effects may indirectly account for some regional distinction.

d) LEI did not conduct this sensitivity analysis, nor did LEI think it was necessary or appropriate to do so given the objective of the benchmarking study (i.e., to compare OPG's relative efficiency to the industry average, not to that of a single peer).

Board Staff Interrogatory #291

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 3 / p. 17

Preamble:

London Economics International LLC (LEI) notes that the Total Cost Benchmarking study excludes environmental costs, regulatory costs, land and water rental fees, and capability enhancing capital investments.

Question(s):

a) Please discuss how these exclusions affect comparability between Canadian and U.S. operators. Are environmental costs, regulatory costs, land and water rental fees, and capability enhancing capital investments comparable as between Canada and the U.S.?

b) Please explain whether LEI considered including more comprehensive capital spending measures beyond sustaining capital; If not, please explain the reason.

c) Please explain how LEI and OPG ensure that the results are applicable to OPG's sought approvals given that major refurbishment investments were excluded.

Response

Except as noted below, this response was prepared by London Economics International LLC ("LEI")

a) See response to Ex. L-A1-Staff-290 part (c).

b) LEI's reasoning for focusing on sustaining capital is described in response to Ex. L-A1-Staff-282 part (g)(iv).

c) LEI's reasoning for focusing on sustaining capital for the benchmarking analysis is described in response to Ex. L-A1-Staff-282 part (g)(iv). Although certain operating expenses and capital investments were not included in the benchmarking model, LEI is confident that the empirical findings from the benchmarking analysis provide valuable input to the OEB for setting the stretch factor in OPG's Custom IR plan.

Our assessment of relative performance appropriately places OPG relative to its peers in the top quintiles.

The remainder of this response was prepared by OPG.

While LEI's benchmarking analysis used to determine the stretch factor focuses on sustaining capital, OPG proposes to apply the stretch factor more broadly: (i) as part of the X-factor reduction in the annual adjustment mechanism (see Ex. A1-3-2, p. 9), and (ii) as a reduction on all capital-related revenue requirement (see Ex. A1-3-2, p. 17 and Ex. I1-2-1, Table 2, line 6).

Board Staff Interrogatory #292

Interrogatory

Reference:
Ref 1: Exhibit I1 / Tab 2 / Schedule 1
Ref 2: Exhibit A1 / Tab 3 / Schedule 2
Ref 3: Alberta Utilities Commission, Decision 27388-D01-2023 (October 4, 2023) Appendix 7 (K-bar calculation) pp. 126-128
Ref 4: Lowry, Mark Newton, David Hovde, Rebecca Kavan and Matthew Makos, "Impact of Multiyear Rate Plans on Power Distributor Productivity: Evidence from Alberta,"), The Electricity Journal, Volume 36, Issue 5, June 2023
Ref 5: EB-2023-0195 Exhibit M1
Ref 6: Attachment "A1-03-Staff-292 Table 1 – OPG K-Bar Table.xlsx"
Ref 7: Attachment "A1-03-Staff-292 Tables 2a-b – Calculating K-Bar Escalation Factors.xlsx"

Preamble:

OEB staff would like to explore alternative approaches to Custom IR for OPG, and in particular, exploring the increasingly popular K-bar alternative. In this approach, capital revenue escalation in a multiyear rate plan depends in whole or in part on the utility's recent historical gross plant additions (escalated in some plans for input price inflation and growth in operating scale) instead of forecasted additions. This approach, pioneered in California, is now also used by regulators in Alberta and Massachusetts. Research by PEG found that the establishment of the K-bar approach to capital revenue escalation coincided with a material acceleration in the capital productivity growth of Alberta power distributors.

PEG has developed a hypothetical K-bar approach that differs in important respects from that in Alberta in order to better dovetail with OPG's stated capex needs and proposed Custom IR framework in this proceeding. K bar would not apply to some capex categories, and it should be possible to preserve the I – X + C + GRCF formula that OPG proposes. The formula would not contain an explicit K-Bar term.

It is impractical for PEG to do the required financial calculations. As in Reference 5, in Toronto Hydro-Electric System Limited (THESL)'s 2023 Custom IR proceeding, PEG identified capital expenditures that could have been subject to K-bar treatment. Several additional steps would have been required to calculate capital or total revenue requirements. In the present proceeding, for example, historical plant additions in asset categories eligible for K-bar treatment would have to be escalated to reflect business conditions during the proposed plan and converted into budgets for each year of the plan. These budgets would then have to be added to the Company's (gradually

depreciating) rate base of older assets along with plant additions for the asset categories to be determined with forecasts. The appropriate return on rate base, depreciation expenses, and taxes would then be calculated. PEG is not well-positioned to undertake these critical steps in the revenue requirement calculations.

Question(s):

a) Please provide revenue requirement growth rate projections for each year of the proposed plan period (2027-2031) that are comparable to the Company's proposal and consistent with the following assumptions.
   i. Revenue requirement for 2027 as OPG proposes.

   ii. Revenue requirement for OM&A expenses net of other operating revenue in years 2028-2031 as OPG proposes.

   iii. Capital-related revenue requirement from 2028 to 2031 calculated as OPG proposes except for an alternative basis for some gross plant additions. Gross plant additions eligible for forecasting and K-bar treatment are identified in the attached Table 1.

   iv. Gross plant additions designated for K-bar treatment would be based on averages of the Company's 2022-2024 actual additions and 2025-26 budgeted additions escalated for annual inflation and OPG capacity growth to the applicable "out" years of the proposed plan (2028-31). Here are the steps in this calculation, which have been implemented by PEG using escalators developed in Tables 2a and 2b.
      1) For each of the years from 2022 to 2026, gross plant additions in the capital categories designated for K-bar treatment should be escalated to 2027 for inflation and OPG's capacity growth. The OEB's proposed I-factor formula is used in these calculations for the years for which required data are available. Where inflation forecasts are required, we use forecasts of GDPIPI inflation from Toronto Dominion Economics and of AWE Ontario inflation that PEG purchased from Signal49 Research.
      2) Calculate the average of the K-bar designated gross plant additions that have been escalated to 2027 business conditions for each capital category.
      3) Escalate each of these 2027 averages to the four out years of the proposed plan (2028-2031) using inflation plus capacity growth.

   v. Insert these gross plant additions into the rate base calculations that also include OPG's forecasts of plant additions for other asset categories. The rate base calculations should include depreciation of older plant and plant retirements as in the numbers reported on line 2a of Table 2 in Exhibit I1/Tab 2/Schedule 1 of OPG's Custom IR submission.

vi. Calculate the resultant levels of the Company's capital-related and total revenue requirements for each of the out years of the plan. The results for the level of the Company's total revenue requirement should be comparable to the result in line 14 of Table 2, while the results for the level of the Company's Capital-Related Revenue Requirement should be comparable to the result in line 7 of Table 2. Calculate the capital related revenue requirement shortfall and C-Factor in the same manner as in lines 9 and 10 of Table 2.

Please apply a reasonable approach regarding the value of disposals or other implementation complications and provide the assumptions you relied upon in your response

vii. The resultant growth in the Capital-Related Revenue Requirement would be subject to a 0.15% X factor markdown, as OPG has proposed.

viii. The portions of the capital revenue requirement that are accorded K-bar treatment would not be subject to OPG's proposed underspend clawback.

PEG is available to help OPG with questions that arise as it undertakes its response.

Response

OPG respectfully declines to undertake the K-Bar analysis and calculations requested in this interrogatory for several reasons, outlined below. These analyses are not relevant to evaluating OPG's proposed Custom IR framework for the regulated hydroelectric facilities and are not practicable within the time available for responding to interrogatories.

OPG developed its proposed Custom IR rate-setting framework for the company's regulated hydroelectric facilities based on the principles outlined in the OEB's Renewed Regulatory Framework ("RRF"). The RRF specifies that Custom IR is most appropriate for utilities "with significantly large multi-year or highly variable investment commitments that exceed historical levels."[1]

Based on the materials provided by PEG and preliminary research, OPG understands that the K-bar mechanism fundamentally relies on historical capital additions to determine capital funding for future periods. This approach appears to be misaligned with the OEB's Custom IR rate-setting method, which is explicitly based on a utility's

[1] Report of the Board: Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach (RRF), p. 19.

five-year capital forecasts for the upcoming rate period.[2] The Custom IR rate-setting method has been approved for numerous utilities on this basis for over a decade, whereas, to OPG's knowledge, the historical K-bar approach has never been used or endorsed by the OEB in any previous decision or rate-setting policy document.

OPG is not familiar with the details of the K-bar mechanism, either in the jurisdictions cited in the preamble to this interrogatory or the modified version proposed by PEG. Therefore, it is not practicable for OPG to consider the issues that could arise from adopting K-bar rate-setting during the discovery phase of this Application.

When first establishing the incentive rate-setting frameworks that apply to OPG, the OEB undertook a consultative process (EB-2012-0340). If the OEB determines that new forms of incentive rate-setting should be considered for OPG's prescribed assets, beyond those set out in the RRF, OPG believes this should occur through a consultative process, well in advance of a payment amounts proceeding.

[2] RRF, p. 18.

Board Staff Interrogatory #294

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / pp. 30-34
Ref 2: Exhibit I1 / Tab 3 / Schedule 1 / Table 2
Ref 3: Exhibit I1 / Tab 1 / Schedule 1 / Tables 2 and 2a

Preamble:

Reference 1 describes OPG's proposed stretch factor. This proposal includes the limited application of the stretch factor to only a portion of the OPG Nuclear revenue requirement.

Reference 2 provides the details of the calculation of the OPG Nuclear stretch factor.

Reference 3 is the two tables that provide a summary of the OPG Nuclear and the DNNP 2027 to 2031 revenue requirements.

Question(s):

a) Please confirm that the entirety of the Applicants' basis for the application of a stretch factor to the revenue requirement related to the DNNP facilities is contained in lines 5 to 23 on page 31 of Reference 1. If not confirmed, please provide references to the pre-filed evidence and summarize the additional information.

b) Please provide a detailed breakdown for the OPG Nuclear and DNNP revenue requirement that is not subject to the proposed stretch factor. Please do so at the level of Reference 2, including the supplementary notes. Please explain an additional reconciliation between Reference 3 and the sum of this response and Reference 2.

Response

a) Not confirmed. Line 17 at Ex. A1-3-2, p. 31 references Ex. D2-4-1 and related evidence for the DNNP. These are important references to understand the greenfield nature and unique aspects of the project and why it would not be appropriate to apply a stretch factor to costs and revenue requirement impacts associated with the DNNP facilities in this proceeding.

b) A detailed breakdown of OPG nuclear facilities' proposed revenue requirements over the 2028-2031 period not subject to the proposed stretch factor is included as Attachment 1. A reconciliation between Reference 3 and the sum of Attachment 1 and Reference 2 is provided in the Charts below.

As discussed at Reference 1 and part a) of this response, the Application is not proposing a stretch factor apply to costs associated with the DNNP facilities. Thus, none of the revenue requirement impacts included in Ex. I1-1-1, Table 2a are proposed to be subject to the stretch factor.

Chart 1: Reconciliation Between Reference 3 and the Sum of Reference 2 and Attachment 1 for OPG Nuclear Facilities – 2028

Component	Subject to Stretch	Not Subject to Stretch	Total	Revenue Requirement Total	Difference
	(Ex. I1-3-1, Table 2)	(Att. 1, Table 1)		(Ex. I1-1-1, Table 2)	
Cost of Capital	343.0	801.9	1,144.9	1,144.9	-
OM&A	1,681.1	75.0	1,756.0	1,756.0	-
Fuel	-	221.7	221.7	221.7	-
Depreciation & Amortization	282.6	425.9	708.5	708.5	-
Property Tax	-	14.2	14.2	14.2	-
Less: Other Revenues	-	44.2	44.2	44.2	-
CCR – PRP	-	479.9	479.9	479.9	-
Income Tax	11.5	(28.1)	(16.6)	(16.6)	-
Revenue Requirement	2,318.1	1,946.3	4,264.4	4,264.4	-

Chart 2: Reconciliation Between Reference 3 and the Sum of Reference 2 and Attachment 1 for OPG Nuclear Facilities – 2029

Component	Subject to Stretch	Not Subject to Stretch	Total	Revenue Requirement Total	Difference
	(Ex. I1-3-1, Table 2)	(Att. 1, Table 1)		(Ex. I1-1-1, Table 2)	
Cost of Capital	367.2	783.3	1,150.5	1,150.5	-
OM&A	1,882.1	35.3	1,917.4	1,917.4	-
Fuel	-	223.6	223.6	223.6	-
Depreciation & Amortization	304.5	425.8	730.3	730.3	-
Property Tax	-	14.5	14.5	14.5	-
Less: Other Revenues	-	(4.3)	(4.3)	(4.3)	-
CCR – PRP	-	667.7	667.7	667.7	-
Income Tax	(10.6)	(6.0)	(16.6)	(16.6)	-
Revenue Requirement	2,543.1	2,148.5	4,691.6	4,691.6	-

Chart 3: Reconciliation Between Reference 3 and the Sum of Reference 2 and Attachment 1 for OPG Nuclear Facilities – 2030

Component	Subject to Stretch	Not Subject to Stretch	Total	Revenue Requirement Total	Difference
	(Ex. I1-3-1, Table 2)	(Att. 1, Table 1)		(Ex. I1-1-1, Table 2)	
Cost of Capital	436.3	761.8	1,198.1	1,198.1	-
OM&A	1,826.7	29.6	1,856.3	1,856.3	-
Fuel	-	261.2	261.2	261.2	-
Depreciation & Amortization	354.5	425.4	779.8	779.8	-
Property Tax	-	14.8	14.8	14.8	-
Less Other Revenues	-	20.8	20.8	20.8	-
CCR – PRP	-	832.0	832.0	832.0	-
Income Tax	7.3	(23.9)	(16.6)	(16.6)	-
Revenue Requirement	2,624.8	2,280.0	4,904.8	4,904.8	-

Chart 4: Reconciliation Between Reference 3 and the Sum of Reference 2 and Attachment 1 for OPG Nuclear Facilities – 2031

Component	Subject to Stretch	Not Subject to Stretch	Total	Revenue Requirement Total	Difference
	(Ex. I1-3-1, Table 2)	(Att. 1, Table 1)		(Ex. I1-1-1, Table 2)	
Cost of Capital	516.5	1,162.5	1,679.0	1,679.0	-
OM&A	2,122.0	31.4	2,153.5	2,153.5	-
Fuel	-	306.1	306.1	306.1	-
Depreciation & Amortization	414.6	578.0	992.6	992.6	-
Property Tax	-	15.0	15.0	15.0	-
Less: Other Revenues	-	6.5	6.5	6.5	-
CCR – PRP	-	646.2	646.2	646.2	-
Income Tax	26.3	(42.9)	(16.6)	(16.6)	-
Revenue Requirement	3,079.4	2,689.9	5,769.3	5,769.3	-

Numbers may not add due to rounding.

Table 1
OPG Nuclear Revenue Requirement Not Subject to Stretch Factor
January 1, 2027 to December 31, 2031 ($M)

Line No.	Description	Note	2027	2028	2029	2030	2031
			(a)	(b)	(c)	(d)	(e)
	Nuclear OM&A Expenses Not Subject to Stretch Factor						
1	Base OM&A	1		0.0	0.0	0.0	0.0
2	Project OM&A	2		11.7	10.5	10.2	6.4
3	Outage OM&A	3		0.0	0.0	0.0	0.0
4	Allocation of Corporate Costs	4		0.0	0.0	0.0	0.0
5	Pickering Cyclical Maintenance OM&A	5		0.0	0.0	0.0	0.0
6	Pickering Refurbishment OM&A	6		94.1	84.9	52.7	46.5
7	Allocation of Centrally Held Costs	7		(30.8)	(60.1)	(33.3)	(21.6)
8	**Total OM&A Expenses Not Subject to Stretch Factor** (line 1 through line 7)			75.0	35.3	29.6	31.4
9	Asset Service Fees	8		0.0	0.0	0.0	0.0
9a	Fuel Expense	13		221.7	223.6	261.2	306.1
	Nuclear Capital Related Revenue Requirement Not Subject to Stretch Factor						
	Darlington Refurbishment Program Related Revenue Requirement						
10	Cost of Capital	10		689.4	665.8	639.2	610.9
11	Depreciation Expense	10		410.5	410.4	410.0	410.0
12	Income Tax Expense on Cost of Capital and Depreciation Expense	10		291.6	285.1	278.5	272.0
13	**Total DRP Capital Related Revenue Requirement Not Subject to Stretch Factor** (line 10 + line 11 + line 12)			1,391.5	1,361.3	1,327.6	1,292.9
	Pickering Refurbishment Program Capital Related Revenue Requirement						
14	Cost of Capital	11		12.2	12.0	11.7	437.5
15	Depreciation Expense	11		4.1	4.1	4.1	156.7
16	Income Tax Expense on Cost of Capital and Depreciation Expense	11		4.1	4.0	4.0	149.2
17	**Total PRP Capital Related Revenue Requirement Not Subject to Stretch Factor** (line 14 + line 15 + line 16)			20.3	20.0	19.7	743.4
18	Revenue Requirement of Working Capital and Cash Working Capital	9		82.1	88.2	95.5	100.3
19	Revenue Requirement of Asset Retirement Costs	12		55.8	56.0	55.1	54.2
20	Income Tax Expense- Capital Cost Allowance Not Subject to Stretch Factor			(349.9)	(322.4)	(334.7)	(493.1)
21	Property Tax	14		14.2	14.5	14.8	15.0
22	Less: Other Revenues	15		44.2	(4.3)	20.8	6.5
23	Concurrent Cost Recovery - Pickering Refurbishment Program	16		479.9	667.7	832.0	646.2
24	**Total Revenue Requirement Amount Not Subject to Stretch Factor** sum of lines (8, 9, 9a, 13, 17, 18, 29, 20, 21, 23) less line 22			1,946.3	2,148.5	2,280.0	2,689.9

Notes:
Refer to Table 1a

Table 1a
Notes to Ex. L-A1-Staff-294, Attachment 1, Table 1

Notes:
1 All Base OM&A costs are subject to the stretch factor.
2 From Ex. F2-3-1, Table 1: line 3c + line 3f.
3 All Outage OM&A costs are subject to the stretch factor.
4 All Nuclear Allocations of Corporate Costs are subject to the stretch factor.
5 All Pickering Cyclical Maintenance OM&A costs are subject to the stretch factor.
6 From Ex. F2-1-1 Table 1a, line 11.
7 From Ex. F2-1-1 Table 1a, line 12.
8 All Nuclear Asset Service Fees are subject to the stretch factor.
9 Cost of capital component of Working Capital and Cash Working Capital Related Revenue Requirement for 2028-2031 is calculated as follows:

		2027	2028	2029	2030	2031
9a	Working Capital and Cash Working Capital (Ex. I1-1-1, Table 2: sum of lines 2 and 3)		952.9	1,017.7	1,098.4	1,152.1
9b	Return on Equity at ROE Rate (line 9a x 52% x 9.11%)		45.1	48.2	52.0	54.6
			-	-	-	-
9c	Cost of Debt (line 9a x 48% x Ex. C1-1-1, Tables 1-4, col. (c), line 4)		21.9	23.9	26.1	27.5
9d	Total Cost of Capital (lines 9b + 9c)		**67.0**	**72.1**	**78.2**	**82.1**
9f	Net Regulatory Taxable Income Increase / (Decrease) (line 9b)		45.1	48.2	52.0	54.6
9g	Income Tax Expense (line 10h x 25% / (1 - 25%))		**15.0**	**16.1**	**17.3**	**18.2**

10 Cost of capital component of Darlington Refurbishment Program Capital Related Revenue Requirement for 2028-2031 is calculated as follows:

		2027	2028	2029	2030	2031
10a	Darlington Refurbishment Program Fixed Asset Rate Base. 2028: Ex. B3-3-1, Table 2, col. (f), lines 14 and 15 less Ex. B3-4-1 Table 2, col. (f), lines 38 and 39. 2029: Ex. B3-3-1, Table 2, col. (f), lines 26 and 27 less Ex. B3-4-1 Table 2, col. (f), lines 50 and 51. 2030: Ex. B3-3-1, Table 2, col. (f), lines 38 and 39 less Ex. B3-4-1 Table 2, col. (f), lines 62 and 63. 2031: Ex. B3-3-1, Table 2, col. (f), lines 50 and 51 less Ex. B3-4-1 Table 2, col. (f), lines 74 and 75.		9,802.6	9,392.1	8,981.9	8,571.9
10c	Return on Equity at ROE Rate (line 10a x 52% x 9.11%)		464.4	444.9	425.5	406.1
10e	Cost of Debt ((line 10a) x 48% x Ex. C1-1-1, Tables 1-4, col. (c), line 4)		225.0	220.9	213.7	204.8
10f	Total Cost of Capital (lines 10c + 10e)		**689.4**	**665.8**	**639.2**	**610.9**
10g	Depreciation Expense (Ex. B3-4-1, Table 2, col. (b) plus col. (c): lines 38 & 39; lines 50 & 51; lines 62 & 63; lines 74 & 75)		410.5	410.4	410.0	410.0
10h	Net Regulatory Taxable Income Increase / (Decrease) (line 10c + line 10g)		874.9	855.3	835.5	816.0
10i	Income Tax Expense (line 10h x 25% / (1 - 25%))		**291.6**	**285.1**	**278.5**	**272.0**

11 Cost of capital component of Pickering Refurbishment Program Capital Related Revenue Requirement for 2028-2031 is calculated as follows:

		2027	2028	2029	2030	2031
11a	Pickering Refurbishment Program Net Fixed Asset Rate Base. 2028: Ex. B3-3-1, Table 2, col. (f), line 18 less Ex. B3-4-1 Table 2, col. (f), line 42. 2029: Ex. B3-3-1, Table 2, col. (f), line 30 less Ex. B3-4-1 Table 2, col. (f), line 54. 2030: Ex. B3-3-1, Table 2, col. (f), line 42 less Ex. B3-4-1 Table 2, col. (f), line 66. 2031: Ex. B3-3-1, Table 2, col. (f), line 54 less Ex. B3-4-1 Table 2, col. (f), line 78.		172.8	168.7	164.7	6,139.3
11c	Return on Equity at ROE Rate (line 11a x 52% x 9.11%)		8.2	8.0	7.8	290.8
11e	Cost of Debt ((line 11a) x 48% x Ex. C1-1-1, Tables 1-4, col. (c), line 4)		4.0	4.0	3.9	146.7
11f	Total Cost of Capital (lines 10c + 10e)		**12.2**	**12.0**	**11.7**	**437.5**
11g	Depreciation Expense (Ex. B3-4-1, Table 2, col. (b) plus col. (c): lines 42, 54, 66, 78)		**4.1**	**4.1**	**4.1**	**156.7**
11h	Net Regulatory Taxable Income Increase / (Decrease) (line 11c + line 11g)		12.2	12.1	11.9	447.5
11i	Income Tax Expense (line 10h x 25% / (1 - 25%))		**4.1**	**4.0**	**4.0**	**149.2**

12 Cost of capital component of Asset Retirement Cost Capital Related Revenue Requirement for 2028-2031 is calculated as follows:

		2027	2028	2029	2030	2031
12a	Asset Retirement Costs Net Fixed Asset Rate Base. 2028: Ex. B3-1-1, Table 2, col. (i), line 10 less Ex. C1-1-1, Table 4, line 7, col. (a). 2029: Ex. B3-1-1, Table 2, col. (c), line 22. 2030: Ex. B3-3-1, Table 2, col. (f), line 22. 2031: Ex. B3-3-1, Table 2, col. (i), line 22.		459.3	471.0	459.6	448.3
12b	Return on Equity at ROE Rate (line 12a x 52% x 9.11%)		21.8	22.3	21.8	21.2
12c	Cost of Debt (line 12a x 48% x Ex. C1-1-1, Tables 1-4, col. (c), line 4)		10.5	11.1	10.9	10.7
12d	Total Cost of Capital (lines 12b + 12c)		**32.3**	**33.4**	**32.7**	**31.9**
12e	Depreciation Expense (Ex. B3-4-1, Table 2, col. (b): lines 46, 58, 70, 82)		**11.3**	**11.3**	**11.3**	**11.3**
12f	Net Regulatory Taxable Income Increase / (Decrease) (line 12b + line 12e)		33.1	33.7	33.1	32.6
12g	Income Tax Expense (line 12f x 25% / (1 - 25%))		**11.0**	**11.2**	**11.0**	**10.9**
12h	Adjustment for Lesser of Asset Retirement Costs and Unfunded Nuclear Liability Provision		1.1	-	-	-
12i	Revenue Requirement of Asset Retirement Costs (line 12d + line 12e + line 12g + line 12h)		**55.8**	**56.0**	**55.1**	**54.2**

13 From Ex. I1-1-1, Table 2, line 16.
14 From Ex. I1-1-1, Table 2, line 18.
15 From Ex. I1-1-1, Table 2, line 22.
16 From Ex. I1-1-1, Table 2, line 22a.

Board Staff Interrogatory #295

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / p. 30
Ref 2: Exhibit A2 / Tab 1 / Schedule 1 / Attachment 2 / p. 4

Preamble:

At Reference 1, OPG states:

> 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.

In Reference 2, OPG states:

> 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.

Question(s):

a) Given the last unit of Darlington GS has returned to service in early 2026, please list the categories of revenue requirement related to the DRP that will not be subject to the stretch factor in the 2027-2031 rate term.

Response

a) The Darlington Refurbishment Program ("DRP") costs that are not subject to the proposed stretch factor are presented in Ex. B3-1-1, Table 2, lines 2 and 3 (i.e., the DRP excluding the Heavy Water Storage Facility and Heavy Water Storage Facility). The resulting revenue requirement categories excluded from the proposed stretch factor are the associated cost of capital, depreciation and income tax expense.

Board Staff Interrogatory #296

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / p. 30-32

Preamble:

In Reference 1, OPG states:

> 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.

OPG also states that "the Pickering Nuclear Generating Station is not forecast to produce electricity until partway through 2031, when the first unit is scheduled to return to service."

Question(s):

a) Given that the Pickering Nuclear Generating Station is not forecast to produce electricity for most part of the 2027-2031 rate term, please explain the criteria used to distinguish between Pickering OM&A expenses that are covered under the stretch factor from OM&A costs that are exempted from the stretch factor.

Response

a) Consistent with the treatment of the Darlington Refurbishment Program ("DRP"), OPG's proposal is to exclude the capital and Project OM&A costs forming part of the Pickering Refurbishment Program ("PRP") from the stretch factor. Such Project OM&A expenses are discussed in Ex. F2-8-1. OPG does not propose to exclude, on account of the PRP, any OM&A expenses not forming part of the PRP from the stretch factor.

   As described at Ex. A1-3-2, p. 30, "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."

Board Staff Interrogatory #297

Interrogatory

Reference:
Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / p. 2
Ref 2: Exhibit A1 / Tab 3 / Schedule 2 / pp. 30-31

Preamble:

Regarding the proposed Custom IR framework for nuclear facilities, OPG in Reference 1 states:

> 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 with a standard price-cap framework.

OPG states in Reference 2:

> 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." For DNNP expenditures, OPG also states that "the DNNP is a large, singular investment to building a new nuclear facility that will not be in 'steady state' operations during the IR term.

Question(s):

a) Excluding discrete investments such as the PRP and the DNNP, has OPG considered using a standard Price Cap IR formula for the remaining core business operations?

b) If OPG considers a standard Price Cap IR formula to be inappropriate for the remaining core business operations, please explain why.

Response

a) and b)
The Applicants did not consider a price-cap index formula for their nuclear rate-setting proposal. A price-cap index formula approach would be inconsistent with Ontario Regulation 53/05 ("O. Reg. 53/05"), which, as discussed in Ex. A1-3-2, Section 3.1, requires that nuclear payment amounts in this Application be

established based on the individually approved annual revenue requirements for OPG's regulated nuclear facilities and the DNNP facilities. Specifically, O. Reg. 53/05, section 14(2)7 states:

> In determining the base payment amount for the nuclear facilities and the DNNP Nuclear Generating Station for any year before the effective date of the first DNNP post-construction payment order, the Board shall determine a blended base payment amount for Ontario Power Generation Inc. and the DNNP generator, calculated using the formula:
>
> (A + B) / (C + D)
>
> where,
>
> "A" is the Board-approved revenue requirement for the nuclear facilities for the year,
>
> "B" is the Board-approved revenue requirement for the DNNP Nuclear Generating Station for the year,
>
> "C" is the Board-approved production forecast for the nuclear facilities for the year, and
>
> "D" is the Board-approved production forecast for the DNNP Nuclear Generating Station for the year.

As described in Section 3.1 of Ex. A1-3-2, the nuclear Custom IR framework is appropriate for this legislative context and meets the needs of the nuclear facilities and the DNNP facilities over the IR term, while reflecting the principles of the Renewed Regulatory Framework and the OEB's prior guidance on incentive ratemaking for OPG's nuclear facilities.

Society Interrogatory #002

Interrogatory

Reference:
Exhibit A1-4-1, Overview of OPG, Section 1.0 Purpose, p1 lns 4-7

Preamble:

"This evidence provides an overview of OPG, including a summary of its mandate, objectives, key assets, corporate governance and organization."

Question(s):

a) Can OPG identify where, within the governance framework climate-related physical risks (such as extreme weather, flooding, drought, temperature variability, etc.) are addressed as enterprise risks?

Response

a) The Enterprise Risk Management Policy and associated governance require business units to identify risks, including climate-related risks, and if warranted, these are elevated to the enterprise level following established risk management processes.

Society Interrogatory #005

Interrogatory

Reference:
Exhibit A1-6-1, Summary of Legislative Framework, p1 lns4-7

Preamble:

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.

Question(s):

a) How does OPG interpret its obligations under the OEB Act and its generation licence, as described with respect to managing and mitigating climate related physical risks to system reliability and cost stability?

Response

a) There are no specific climate-related provisions applicable to OPG under the OEB Act or its generation licence.

VECC Interrogatory #001

Interrogatory

Reference:
Exhibit A1, Tab 3, Schedule 2, pages 18-20

Preamble:

"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."

Question(s):

a) Please confirm or correct that the X Factor being applied in the example for line 8 of Table 6 is 3.34%.

b) Is the purpose of the C-Factor to ensure the recovery in rates of the entire forecast capital in each year?

Response

a) Not confirmed. The (I-X) adjustment at line 8 of Chart 6 is 3.34%. This is based on an I-factor of 3.49% and X-factor of 0.15%.

b) No. The purpose of the C-factor is to recover incremental revenue each year in order to support substantial capital investments required in the regulated hydroelectric facilities over the forecast period, beyond the amount that would be recovered through the I-X adjustment alone. The C-factor would not ensure recovery of the entire capital related revenue requirement forecast in each year, as it is reduced by a stretch factor adjustment and would be subject to the proposed asymmetric Global Hydroelectric Capital Variance Account, and recovery would be based on the actual production at the regulated hydroelectric facilities. As noted at Ex. A1-3-2, p. 17, "[t]he 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". This is in addition to the

incremental stretch implicit in OPG's proposed productivity of zero, despite negative TFP results identified in the LEI study at Ex. A1-3-2, Attachment 2.[1]

[1] The negative TFP results and implications of a zero productivity factor are discussed at Ex. A1-3-2, p. 15.

VECC Interrogatory #002

Interrogatory

Reference:
Exhibit A1, Tab 3, Schedule 2, pages 20-
Exhibit H1, Tab 1, Schedule 1, page 8
Exhibit F1, Tab 4, Schedule 1, Table 1

Question(s):

a) Was the GRCF proposed in the application EB-2016-0152? If not why not and what factors have since changed (or are now known) which argue for its inclusion in the proposed new rate plan?

b) It is unclear to us what value is added by the inclusion of the GRCF given the existence of the proposed Hydroelectric Water Conditions Variance Account (HWCVA) since "[T]his *account records the financial impact of differences, including changes in GRC costs, between the actual production amount for the regulated hydroelectric facilities and the reference production amount, arising from changes in actual water conditions*." What variance is captured as between the amounts shown for GRC in 2027 at Exhibit F1, Tab 4, Schedule 1 and the actual amounts incurred between 2027 and 2031?

Response

a) No, OPG did not propose a GRCF in EB-2016-0152. As discussed at Ex. A1-3-2, Section 2.3.4, "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 rate-setting framework approved in EB-2016-0152 was a typical price cap framework that did not include a C-factor or a GRCF.

b) There is no overlap between the proposed GRCF and the Hydroelectric Water Conditions Variance Account.

The GRCF is designed to hold the GRC expense embedded in payment amounts constant over the IR term. Absent the GRCF, the annual (I-X) adjustment would effectively escalate the GRC amounts embedded in payment amounts. The value of the GRCF, therefore, is in lowering regulated hydroelectric payment amounts through the removal of the escalation associated with GRC amounts.

The purpose of the Hydroelectric Water Conditions Variance Account is to address the impact of water conditions, which are beyond OPG's ability to manage or control. The reference to GRC costs in the quote included in the question is in recognition that the financial impact of higher-or-lower production arising from changes in actual water conditions includes changes in GRC costs.

VECC Interrogatory #003

Interrogatory

Reference:
Exhibit A1-3-2 Attachments 4

Question(s):

a) How are the 2024 and 2025 targets established for the regulated hydroelectric performance scorecard?

b) Please update Attachment 4 to show the targets for each year 2021 to 2023 and provide the actual 2025 results.

c) Does OPG have targets for 2026? If so please provide these.

d) Does OPG have targets for the duration of the rate plan? If so please provide the annual 2027-31 targets.

Response

a) Regulated hydroelectric performance scorecard targets are established as described in Ex. F1-1-1, Section 4.0.

b) Refer to Ex. F1-1-1, Section 4.0 for the 2021-2023 targets. The 2025 actuals for Total Recordable Injury Frequency, Environmental Performance Index, Availability, Equivalent Forced Outage Rate, Unit Energy Costs and Total Generation Costs are provided in Ex. L-F1-SEC-153.

c) Refer to Ex. F1-1-1, Section 4.0 for the following 2026 targets: Total Recordable Injury Frequency, Availability, Equivalent Forced Outage Rate, and Unit Energy Cost.

As described in Ex. F1-1-1, Section 4.2 Environmental Performance Indicator will be replaced by a new metric, Total Recordable Environmental Events ("TREE"). The 2026 TREE targets are identified in Ex. F1-1-1, Section 4.2, Chart 5.

Consistent with historical practice, as explained in EB-2016-0152[1], OPG does not set Total Generating Cost targets for the regulated hydroelectric business.

[1] OPG Reply Argument, EB-2016-0152, June 19, 2017, p. 220; Decision and Order, EB-2016-0152, December 28, 2017, pp. 148-149.

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d) Refer to Ex. F1-1-1, Section 4.0 for annual 2027-2031 targets.

VECC Interrogatory #004

Interrogatory

Reference:
Exhibit A1-3-2 Attachments 5

Question(s):

a) How are the 2024 and 2025 targets established for the following"
   i. Total Generating Cost per Net MWh ($/MWh);
   ii. Normalized Total Generating Cost per Net MWh ($/MWh);
   iii. Total Generating Cost per Unit ($M/unit); and,
   iv. Normalized Total Generating Cost per Unit ($M/unit).

b) Please clarify the meaning of the acronym "OPGN.

c) Please update Attachment 5 to show the targets for each year 2021 to 2023 and provide the actual 2025 results.

d) Does OPG have targets for these categories in 2026? If so please provide them.

e) Does OPG have targets for these categories for the duration of the rate plan? If so please provide these annual 2027-31 targets.

Response

a) OPG Nuclear's targets, including Value for Money targets, are established annually as part of the business planning process described in Ex. F2-1-1, Section 3.0. Normalization of Value for Money metrics is described in Ex. F2-1-1, Section 3.2.1, and in Ex. F2-1-1, Attachment 4.

b) OPGN refers to OPG's Nuclear Operations.

c) Refer to Attachment 1.

d) and e) Yes. For Pickering's Value for Money targets, refer to Ex. L-F2-Staff-183, Chart 1 and for Pickering's Safety, Reliability, and Human Performance targets refer to Ex. F2-1-1, Chart 3, pp. 19-22. For Darlington's Value for Money targets, refer to Ex. L-F2-Staff-179, part c), Chart 1 and for Darlington's Safety, Reliability, and Human Performance targets, refer to Ex. F2-1-1, Chart 4, pp. 23-26.

Attachment 1: 2024 Nuclear Scorecard from Ex. A1-3-2, Attachment 5 with Targets for 2021-2023 and 2025 Actual Results

2025 Nuclear Performance Scorecard

Performance Outcomes	Measures (single-year unless otherwise noted)	2020	2021		2022		2023		2024		2025		Historical Trend	
		Actual	Actual	Target	Actual	Target	Actual	Target	Actual	Target	Actual	Target		
Safety	**Total Recordable Injury Frequency** (#/200k hours worked)													
	Pickering	0.19	0.10	0.20	0.27	0.20	0.20	0.20	0.20	0.20	0.07	0.20	●	+
	Darlington	0.25	0.07	0.20	0.08	0.20	0.00	0.20	0.20	0.20	0.08	0.20	●	-
	Total Industrial Safety Accident Rate (#/200k hours)[1]													
	Pickering	0.00	0.03	0.10	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	●	+
	Darlington	0.00	0.00	0.10	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	●	N
	Collective Radiation Exposure (person rem/unit)													
	Pickering	107.41	67.74	94.50	69.99	101.00	67.17	103.50	103.50	78.90	34.14	59.30	●	+
	Darlington	29.97	110.47	126.20	29.90	27.74	15.64	19.81	19.81	84.80	11.26	25.57	●	+
	Airborne Tritium Emissions (curies/unit)													
	Pickering	2,918	2,331	2,250	2,229	2,250	2,164	2,170	1,820	2,170	1,392	2,000	●	+
	Darlington	879	905	970	1,157	1,001	1,000	1,115	958	1,305	1,060	1,215	●	-
	Fuel Reliability Index (microcuries /gram)													
	Pickering	0.0001	0.0008	0.0005	0.0002	0.0005	0.0003	0.0005	0.0002	0.0005	0.0009	0.0005	●	-
	Darlington	0.0035	0.0002	0.0005	0.0001	0.0005	0.0001	0.0005	0.0029	0.0005	0.002	0.001	●	-
	Reactor Automatic and Manual Trip Rate (#/7000 hours)[2]													
	Pickering	0.00	0.00	0.50	0.14	0.50	0.25	0.50	0.320	0.500	0.36	0.50	●	-
	Darlington	0.00	0.00	0.50	0.00	0.50	0.10	0.50	0.10	0.50	0.10	0.50	●	-
	Auxiliary Feedwater System Unavailability (#)													
	Pickering	0.01	0.01	0.02	0.00	0.02	0.00	0.02	0.00	0.00	0.00	0.00	●	N
	Darlington	0.00	0.00	0.02	0.00	0.02	0.00	0.00	0.0000	0.0000	0.00	0.00	●	N
	Emergency AC Power Unavailability (#)													
	Pickering	0.000	0.000	0.025	0.000	0.025	0.000	0.000	0.0000	0.0000	0.000	0.025	●	N
	Darlington	0.000	0.000	0.025	0.000	0.000	0.000	0.000	0.0000	0.0000	0.000	0.000	●	N
	High Pressure Safety Injection Unavailability (#)													
	Pickering	0.00	0.00	0.02	0.00	0.02	0.00	0.00	0.0000	0.0000	0.00	0.02	●	N
	Darlington	0.00	0.00	0.02	0.00	0.02	0.00	0.00	0.0000	0.0000	0.00	0.00	●	N
Reliability	**WANO Nuclear Performance Index Rolling Average** (%)[3]													
	Pickering	82.50	73.80	77.10	80.90	76.70	81.20	81.00	84.95	85.00	88.11	82.75	●	+
	Darlington	93.60	85.80	86.00	91.40	95.10	89.40	91.80	74.74	78.90	71.11	80.20	●	-
	OPGN	85.30	76.80	79.40	82.40	79.30	82.30	82.50	83.25	84.20	82.44	82.24	●	+
	Forced Loss Rate (%)													
	Pickering	2.65	6.22	3.50	1.81	3.50	2.78	3.50	2.56	3.50	2.96	3.50	●	+
	Darlington	1.54	3.52	3.79	7.51	2.12	1.44	3.24	12.07	4.61	2.01	3.61	●	-
	Unit Capability Rate (%) *													
	Pickering	--	--	--	--	--	--	--	96.36	96.37	96.72	96.20	●	+
	Darlington	--	--	--	--	--	--	--	86.97	94.12	97.18	95.28	●	+
	OPGN	--	--	--	--	--	--	--	92.71	95.54	96.98	95.67	●	+
	Unit Capability Factor (%)[4]													
	Pickering	76.25	78.92	80.05	80.01	74.08	80.66	77.81	83.30	80.91	91.49	89.14	●	+
	Darlington	93.05	82.66	76.04	86.99	85.79	96.99	96.78	74.58	81.26	95.69	94.19	●	+
	OPGN	84.45	80.70	78.19	82.66	78.52	86.68	84.34	79.90	81.04	93.86	91.99	●	+
	Chemistry Performance Indicator (Index)													
	Pickering	1.06	1.06	1.01	1.03	1.02	1.18	1.01	1.22	1.15	1.08	1.09	●	-
	Darlington	1.01	1.01	1.01	1.00	1.01	1.01	1.00	1.03	1.00	1.05	1.05	●	-
	On-line Deficient Non-Critical Backlog (work orders / unit)													
	Pickering	88.00	68.00	57.00	39.80	47.00	29.50	35.00	20.20	20.00	12.75	14.00	●	+
	Darlington	96.00	70.33	90.00	61.00	75.00	29.00	45.00	17.33	20.00	12.33	14.00	●	+
	On-line Deficient Critical Backlog (work orders /unit)													
	Pickering	0.50	1.30	0.00	0.80	0.00	0.67	0.00	0.60	0.00	0.00	0.00	●	+
	Darlington	1.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	●	N
	On-line Corrective Non-Critical Backlog (work orders /unit)													
	Pickering	3.00	6.30	2.00	3.80	2.00	0.83	2.00	1.20	1.00	0.25	0.00	●	+
	Darlington	2.30	2.00	2.00	0.50	0.60	0.00	0.00	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	0.00	0.00	0.00	0.00	●	+
	Darlington	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	●	N
Cost Effectiveness	**Total Generating Cost per Net MWh** ($/MWh)													
	Pickering	67.87	64.75	64.50	60.05	66.45	69.98	63.26	64.30	67.51	70.53	71.57	●	-
	Darlington	54.30	79.27	94.47	101.52	109.33	108.85	120.83	141.94	127.08	71.66	72.18	●	-
	OPGN	60.66	71.53	77.73	76.38	83.79	85.73	85.43	91.78	89.35	71.17	71.92	●	-
	Normalized Total Generating Cost per Net MWh - Updated Methodology ($/MWh)[5]													
	Pickering	--	--	--	--	--	37.36	--	32.03	--	32.04	32.77	●	+
	Darlington	--	--	--	--	--	41.10	--	49.37	--	35.14	34.78	●	-
	OPGN	--	--	--	--	--	38.73	--	38.15	--	33.76	33.90	●	-
	Normalized Total Generating Cost per Net MWh - Original Methodology ($/MWh)													
	Pickering	47.94	44.76	45.31	39.55	44.98	48.02	41.08	41.74	44.22	41.78	42.06	●	+
	Darlington	32.23	45.59	58.15	33.88	43.50	36.60	41.03	51.27	42.85	37.28	37.52	●	-
	OPGN	39.71	45.15	50.94	37.32	44.38	43.40	41.06	45.15	43.71	39.24	39.49	●	+
	Total Generating Cost per Unit ($M/unit)													
	Pickering	232.32	227.59	229.93	214.11	218.98	250.49	219.15	228.49	231.25	290.23	284.63	●	-
	Darlington	389.17	489.03	532.35	663.52	690.87	796.56	857.89	780.21	755.89	516.67	507.52	●	-
	OPGN	287.43	314.74	330.74	331.65	342.40	387.01	368.64	372.79	362.41	387.27	380.16	●	-
	Normalized Total Generating Cost per Unit - Updated Methodology ($M/unit)[5]													
	Pickering	--	--	--	--	--	153.88	--	128.77	--	135.95	131.81	●	+
	Darlington	--	--	--	--	--	292.34	--	305.77	--	246.14	240.83	●	-
	OPGN	--	--	--	--	--	188.50	--	175.06	--	183.18	178.53	●	-
	Normalized Total Generating Cost per Unit - Original Methodology ($M/unit)													
	Pickering	177.15	169.54	151.79	151.79	160.12	184.98	153.50	159.69	163.50	183.29	178.70	●	-
	Darlington	241.83	297.90	238.91	238.91	309.26	287.92	315.81	308.25	278.33	282.44	277.54	●	-
	OPGN	199.88	212.33	232.21	174.57	196.25	210.71	191.49	198.55	192.21	225.78	221.06	●	-
	Non-Fuel Operating Cost per Net MWh ($/MWh)													
	Pickering	59.97	57.24	57.18	54.40	60.45	63.24	57.17	57.65	60.75	59.56	59.67	●	-
	Darlington	36.91	57.64	66.89	64.98	69.30	67.14	71.60	95.70	88.53	47.13	48.35	●	-
	Normalized Non-Fuel Operating Cost per Net MWh ($/MWh)													
	Pickering	--	--	--	--	--	--	--	--	--	--	--	-	-
	Darlington	31.33	47.29	55.93	41.51	42.12	41.83	41.33	63.04	55.44	36.81	37.78	●	-
	Fuel Cost per Net MWh ($/MWh)													
	Pickering	3.89	3.72	3.83	3.75	3.76	3.90	3.91	4.29	4.31	5.12	5.15	●	-
	Darlington	4.22	4.00	4.08	3.82	4.05	4.32	4.78	5.29	4.62	5.23	5.02	●	-
	Capital Cost per MW Design Electrical Rating ($k/MW)													
	Pickering	26.59	25.79	24.10	13.12	14.30	19.71	14.62	16.27	16.31	46.69	34.71	●	-
	Darlington	107.55	123.88	150.87	243.57	258.94	311.66	359.41	256.36	229.91	158.52	150.71	●	-
	Normalized Capital Cost per MW Design Electrical Rating ($k/MW)													
	Pickering	--	--	--	--	--	--	--	--	--	--	--	-	
	Darlington	82.96	90.52	119.86	104.28	153.16	133.09	194.34	111.39	106.91	114.84	110.40	●	-
Human Resources	**18-month Human Performance Error Rate** (#/200k ISAR and contractor hours)													
	Pickering	0.02	0.02	0.07	0.06	0.02	0.06	0.00	0.00	0.00	0.03	0.00	●	+
	Darlington	0.02	0.02	0.04	0.00	0.02	0.00	0.00	0.00	0.00	0.02	0.00	●	-

*** TGC/MWh and Non-Fuel Operating Cost per MWh exclude OPEB, Pension and Corporate Asset Service Fees to align with the industry standard.*

**** Design Electrical Rating (DER)*

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 from 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, 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: *Normalized Total Generating Cost per Net MWh - Updated Methodology ($/MWh) and Normalized Total Generating Cost per Unit - Updated Methodology ($M/unit) originated in 2025 and not available for 2021-2024 targets.*

Current Year	
●	Target met
●	Target not met

5-Year Trend	
+	Favourable
-	Unfavourable
N	Neutral

AMPCO Interrogatory #005

Interrogatory

Reference:
Ref: A2-1-1

Question(s):

Please provide OPG's 2025 Audited Annual Consolidated Financial Statements and Management's Discussion and Analysis.

Response

Refer to Ex. L-A2-Staff-010, Attachment 1.

CCC Interrogatory #014

Interrogatory

Reference:
Exhibit A2, Tab 2, Schedule 1, p. 5

Preamble:

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.

Question(s):

a) Please confirm that the Darlington vacuum building outage in 2027 was not included in the production forecast that underpinned rates in any year prior to 2027. If not confirmed, please provide details as to when the outage was originally scheduled.

b) Please confirm that the vacuum building outage can only be deferred with the permission of the CNSC.

c) Please comment on the possibility that OPG may apply to the CNSC to have the vacuum building outage related work deferred, including the maximum number of years of any such deferral.

Response

a) Confirmed.

b) Confirmed.

c) OPG is planning to execute the Darlington Vacuum Building Outage ("VBO") in 2027 as committed to the CNSC and is not planning to apply to the CNSC to have the VBO deferred.

Witness Panel: Nuclear Operations and Nuclear Projects

CCC Interrogatory #015

Interrogatory

Reference:
Exhibit A2, Tab 2, Schedule 1, p. 11

Preamble:

To address these risks, OPG conducted a comprehensive review supported by independent analysis, confirming sustained escalation pressures through 2031 for construction material.

Question(s):

Please provide the comprehensive review and the supporting independent analysis referred to by OPG in this passage. If already included in the application, please provide the cite for the material.

Response

OPG's internal review of construction inflation is provided in Attachment 1. OPG's internal analysis was informed by an independent review of construction cost escalation rates by Kroll Canada Limited ("Kroll"), which is provided in Attachment 2.

OPG's capital planning escalation rates for nuclear and heavy industrial construction incorporated both broad economic factors, including inflation, supply chain considerations and rising demand for heavy industry construction. More specifically, the review relied on a range of Canadian and North American construction cost indices, to validate OPG's approach. Taken together, this analysis helped validate the inflationary trends currently being observed across the applicable indices.

The independent analysis provided by Kroll concluded that OPG's annual forecast construction cost escalation rate of 4.5% for the period 2025-2031 are reasonable and supported by market data and is below the low end of Kroll's sector average range of 4.6%-5.5%.



Construction Cost Analysis

Analysis Summary

OPG's recommendation is based on the following methodology:

- Identify a set of indices that capture inflationary trends across OPG's planned construction spend.
- Review past, near term and long-term construction cost inflation rates across these indices to identify trend and build estimations.
- We have considered the increase in construction activity across the energy and infrastructure industries.

Summary of findings:

- From 2021 – 23, the annual construction cost inflation rate increased by 6% (near term data point)
- The long-term average construction cost inflation rates for these indices sits at is 4.6% (long term data point)

Based on market precedent and probability to negotiate inflation risks with Suppliers, OPG has proposed an escalation of 4.5% from 2025-2031.

OPG used an external agency to validate our methodology proposed percentage. Such review found the approach reasonable.

Supply Chain team will continue to monitor escalation trends and provide guidance for any required adjustments (up or down).

Forecast Guidance

Calendar Year	OPG SC Recommendations *	Kroll Forecast
2025	4.5%	6.0%
2026	4.5%	5.7%
2027	4.5%	5.4%
2028	4.5%	5.1%
2029	4.5%	4.6%
2030	4.5%	4.6%
2031	4.5%	4.6%

*** Recommendation does not apply to:**

- Contracts with CPI as an escalation formula
- Contracts where escalation cap is below recommended percentage
- Fixed Price Contracts

Indices Highlights – Last 3 years

Ontario Power Generation Inc.
Estimation of Annual Electrical Power Generation Construction Costs as of August 1, 2024
Summary of 2021-2023 Annual Construction Cost Inflation Rates

	Ref #	Source	2021	2022	2023
	1	Statistics Canada – Toronto Non-Residential Buildings	9.6%	16.2%	8.2%
	2	Statistics Canada - Toronto Factory Buildings	12.4%	18.7%	9.1%
(1)	3	Handy-Whitman - Nuclear Production Plant North Atlantic			
(1)	4	Handy-Whitman - Nuclear Production Plant North Central			
	5	Construction Analytics - Non-Residential Buildings	8.3%	12.4%	5.4%
	6	Construction Analytics - Non-Building Infrastructure	8.0%	17.4%	6.4%
	7	Turner Building Cost Index	1.9%	8.1%	6.0%
	8	Rider Levett Bucknall Actual Cost Index	4.8%	8.1%	6.9%
	9	Mortenson Construction Cost Index	16.0%	11.3%	3.1%
	10	Bureau of Labor Statistics - Industrial Buiildings	13.4%	20.4%	0.4%
	11	Bureau of Labor Statistics - Non-Residential Buildings	15.2%	18.2%	-1.2%
(1)	12	FM Global Canada Cost Trends - Ontario Industrial Buildings			
(1)	13	Marshall & Swift - Toronto Heavy Industrial with Protected Steel Frame			
(1)	14	RSMeans Historical Cost Indexes - Toronto Overall Construction			
(2)	15	All Items CPI - Toronto	2.9%	6.5%	4.2%
		Average (excluding All Items CPI)	10.2%	13.1%	4.8%
		Median (excluding All Items CPI)	9.7%	12.7%	6.0%

Notes

Due to the terms of Kroll's third-party data subscription agreements, we cannot disclose annual inflation data for the noted series. This data is included in the calculation of our averages and medians, however. Toronto All Items CPI presented for comparison purposes.

Indices Highlights – Average Annual

Estimation of Annual Electrical Power Generation Construction Costs as of August 1' 2024
Summary of Long-Term Average Construction Cost Inflation Rates

Ref #	Data Source	Description	Data Period	Geography	CAGR	Average Annual Δ
1	Statistics Canada - Table 18-10-0276-01	Non-Residential Buildings	1981 - Present	Toronto	4.3%	4.2%
2	Statistics Canada - Table 18-10-0276-01	Factory Buildings	1981 - Present	Toronto	4.8%	4.7%
3	Handy-Whitman Electric Utility Construction Cost Indices	Nuclear Production Plant	1965-2023	U.S. North Atlantic Region	4.7%	4.7%
4	Handy-Whitman Electric Utility Construction Cost Indices	Nuclear Production Plant	1965-2023	U.S. North Central Region	4.5%	4.6%
5	Construction Analytics Building Cost Index	Non-Residential Buildings	2001 - 2023	U.S.	4.3%	4.4%
6	Construction Analytics Building Cost Index	Non-Building Infrastructure	2001 - 2023	U.S.	4.3%	4.4%
7	Turner Building Cost Index	Non-Residential Buildings	2001 - 2023	U.S.	3.7%	3.8%
8	Rider Levett Bucknall Actual Cost Index	Non-Residential Buildings	2001 - 2023	U.S.	4.3%	4.3%
9	Mortenson Construction Cost Index	Non-Residential Buildings	2009 - 2023	U.S.	4.1%	4.2%
10	Bureau of Labor Statistics Producer Price Index	Industrial Buildings	2007-2023	U.S.	3.9%	4.2%
11	Bureau of Labor Statistics Producer Price Index	Non-Residential Buildings	2014-2023	U.S.	4.9%	5.3%
12	FM Global Property Loss Prevention Data Sheets	Industrial Buildings	2013-2023	Ontario	4.0%	4.0%
13	Marshall & Swift Heavy Industrial Buildings	Protected Steel Frame	2014-2023	Toronto	4.1%	4.3%
14	RSMeans Historical Cost Indexes	Overall Construction Costs	2014-2022	Toronto	5.2%	5.3%
15	All Items CPI	Inflation	1971 - Present	Toronto	4.1%	4.1%
	Average (excluding All Items CPI)				4.4%	4.4%
	Median (excluding All Items CPI)				4.3%	4.4%
	Best Comparables (nuclear + Toronto + Ontario)					
	Average					4.5%
	Median					4.6%

Thank you.

Questions?

OPG

KROLL

Construction Cost Escalation Rates for Electrical Power Generation

December 18, 2024

Construction Cost Escalation Analysis as of August 1, 2024

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Exhibits

Exhibit 1.0 Summary of Long-Term Average Construction Cost Escalation Rates

Exhibit 2.0 Summary of 2014-2023 Annual Construction Cost Escalation Rates

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PRIVATE & CONFIDENTIAL

December 18, 2024

Mr. Abhie Vaidya
Director, Category Management & Strategic Sourcing Supply Chain
Ontario Power Generation Inc.
700 University Avenue
Toronto, Ontario M5G 1X6

Dear Mr. Vaidya:

Kroll Canada Limited ("Kroll" or "we") was retained by Ontario Power Generation Inc. ("OPG" or "you") to assist OPG in a review of its estimated historical and forecast construction cost escalation rates, related to the Ontario electrical power generation industry. Specifically, OPG management ("Management") has requested Kroll's comments as to the reasonableness of Management's forecast annual construction cost escalation rates, and that Kroll derive its own forecast rates based on its independent research. We understand that you require this corroboration and analysis as a part of OPG's strategic budgeting exercise for the period from 2025 through 2031. Our work was performed as of August 1, 2024 (the "Effective Date"), and our findings are submitted in this narrative report.

Conclusion

Based on the information and analysis summarized in this report, it is our view that OPG's annual forecast rates are reasonable and supported by market data. Kroll's forecast construction cost escalation rates do not differ materially from those of Management, and are summarized below:

Calendar Year	Forecast Construction Cost Escalation Rate (OPG)	Forecast Construction Cost Escalation Rate (Kroll)	Difference
2025	4.5%	5.5%	1.0%
2026	4.5%	5.0%	0.5%
2027	4.5%	4.6%	0.1%
2028	4.5%	4.6%	0.1%
2029	4.5%	4.6%	0.1%
2030	4.5%	4.6%	0.1%
2031	4.5%	4.6%	0.1%
CAGR	4.5%	4.8%	0.3%

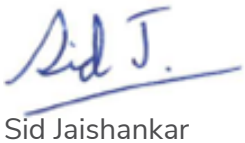
We reserve the right, but will be under no obligation, to review all calculations referred to in this report and, if considered necessary by us, to revise our conclusions in the light of any new facts, trends or changing conditions existing at any date prior to or at the Effective Date, which become apparent to us subsequent to the date of this report.

Independence

Our report has been prepared by persons acting independently and objectively. The fees payable under the terms of our engagement are not contingent upon an action or event resulting from the use of our report.

If you have any questions or comments, please do not hesitate to contact us.

Yours truly,



Sid Jaishankar
Managing Director
Kroll Canada Limited

1.0 Introduction

Ontario Power Generation Inc.

OPG is a commercial enterprise incorporated under the Business Corporations Act (Ontario). Its defined role includes the ownership and operation of a diversified portfolio of electrical power generation assets and the provision of related services. Management estimates that OPG will be making capital investments of approximately $30 billion in generating assets over the next 5 to 7 years, including refurbishing units 5 to 8 at the Pickering Nuclear Generating Station, and building new, small nuclear reactors at Darlington.

OPG is the largest generator of clean electricity in Ontario, but does not distribute electrical power to the end user. That function is performed by Hydro One, which is responsible for transmitting OPG's power, and by local energy utilities such as Hydro Ottawa or Synergy North, who distribute that power to homes and businesses. OPG's sole focus is the generation of electrical power, which it then sells at regulated rates to local utilities through Ontario's wholesale electricity market.

As of Mar. 31, 2024, OPG's generation portfolio had an in-service generating capacity of 18,236 megawatts. It owned and operated:

- 66 hydroelectric stations;
- 2 nuclear stations;
- 1 biomass station;
- 1 dual-fueled oil and gas station;
- 4 combined cycle gas turbine stations owned and operated by wholly-owned subsidiary Atura Power; and
- 1 solar facility.

OPG also owns the following facilities in Ontario and the United States:

- OPG's US Hydroelectric Platform - OPG wholly or jointly owns and operates 85 hydroelectric generating stations and holds minority interests in 14 hydroelectric and two solar facilities in the United States through its US-based wholly-owned subsidiary, Eagle Creek Renewable Energy; and
- Bruce nuclear stations - OPG owns two other nuclear generating stations in Ontario that are leased to Bruce Power L.P.

Purpose and Scope

Kroll's scope of work includes the following services performed in two stages:

Stage 1

- A review of OPG's data sources, methodologies used, and conclusions regarding appropriate escalation rates to be considered for use in its power generation construction contracts for 2025 through 2031.

Stage 2

- Research into any additional construction cost indices identified by Kroll and deemed to be useful in OPG's strategic budgeting exercise;
- An examination of historical and forecast escalation rates regarding the construction of power generation and/or industrial facilities, ideally in the province of Ontario. Kroll will also research such escalation rates for Canada as a whole, and any other jurisdictions deemed to be useful indicators of construction cost escalation;
- Provide our conclusion as to the reasonableness of the annual construction cost escalation rates provided to us by OPG; and
- Provide Kroll's forecast construction cost escalation rates for the 2025-2031 period.

Sources of Information

In the course of our analysis, we relied upon information obtained from various public, financial, and industry sources. Our conclusions are dependent upon such information being complete and accurate in all material respects. However, the scope of our work will not enable us to accept responsibility for the accuracy and completeness of such provided information.

The principal sources of information used in performing our analysis included:

- Statistics Canada;
- Handy-Whitman Index of Public Utility Construction Costs;
- Construction Analytics;
- Turner Building Cost Index;
- Rider Levett Bucknall Actual Cost Index;

- Mortenson Construction Cost Index;
- Bureau of Labor Statistics;
- FM Global Property Loss Prevention Data Sheets;
- Marshall & Swift Valuation Service;
- RSMeans Historical Cost Indices;
- Discussions with Management;
- Ontario Ministry of Finance; and
- Other available information relevant to the estimation of historical and forecast construction cost escalation.

Procedures

In general, our procedures included, but were not limited to, the following:

- Identification and collection of relevant data;
- Analysis of market data, including economic, governmental, and environmental forces;
- Analysis of conditions in, and the outlook for, the Ontario nuclear power generation and broader Ontario electrical power generation industry;
- Provide our conclusion as to the reasonableness of the annual construction cost escalation rates provided to us by OPG for 2025 through 2031;
- Provide our conclusions as to annual forecast construction cost escalation rates for consideration in OPG's strategic planning exercise; and
- Analysis of other facts and data considered pertinent to this analysis.

2.0 General Economic Outlook

Introduction

In performing our analysis, we considered the general economic outlook as of the Effective Date and its potential impact on the subject company. An assessment of the general economy can often identify underlying causes of fluctuations in the financial and operating performance of a company.

Ontario Economic Overview

The following excerpts are quoted from *Building a Better Ontario 2024 Ontario Budget*.

High interest rates are expected to continue negatively impact Ontario's economy in 2024, with real gross domestic product ("GDP") growth projected to slow from an estimated 1.2 per cent in 2023 to 0.3 per cent in 2024. Real GDP growth is projected to accelerate to 1.9 per cent in 2025, and 2.2 per cent in 2026 and 2027. For the purposes of prudent fiscal planning, these projections are slightly below the average of private-sector forecasts.

After a strong start to the year, Ontario's real GDP growth moderated through the course of 2023, as the Bank of Canada's high interest rates weighed on the economy. Real GDP was unchanged in the third quarter of 2023, slowing from gains of 0.6 per cent and 0.4 per cent in the first and second quarters, respectively. Interest-sensitive components such as household consumption and business investment have been particularly impacted by past interest rate increases.

Economic Variable (% Growth)	2022	2023	2024f	2025f	2026f	2027f
Real GDP Growth	3.9	1.2	0.3	1.9	2.2	2.2
Nominal GDP Growth	9.2	4.1	2.7	3.9	4.3	4.1
Employment Growth	4.6	2.4	0.8	1.7	1.4	1.4
CPI Inflation	6.8	3.8	2.6	2.0	2.0	2.0

Employment & Household Spending

High interest rates are projected to contribute to an easing in the labour market in early 2024 before improving later in the year. Employment is projected to rise by 0.8 per cent in 2024, slowing from a 2.4 per cent increase in 2023. The slower employment growth, along with continued robust population and labour force growth, is projected to raise the unemployment rate to 6.7 per cent in 2024. The unemployment rate over the outlook

period is projected to remain below the recent historical average. A strengthening economy is projected to boost employment growth to 1.7 per cent in 2025 and 1.4 per cent in both 2026 and 2027. As employment gains increase, the unemployment rate is expected to gradually decline to 6.2 per cent by 2027.

Slowing demand has helped ease price pressures while population increases have contributed to rising nominal household spending in 2023, which was up 6.0 per cent, after a 13.2 per cent increase in 2022. Despite these strong gains, real spending softened on a per capita basis in 2023 as higher prices and interest costs weighed on household budgets. Canadian household interest payments on debt on a real per capita basis have risen significantly and are at the highest level in over 30 years.

Nominal household spending growth is projected to moderate to 3.5 per cent in 2024 but is expected to accelerate to 4.1 per cent in 2025 as interest rates decrease and the labour market strengthens.

Consumer Price Inflation

Following a significant easing in inflationary pressures in 2023, price pressures are projected to continue to moderate in 2024 as high interest rates continue to dampen demand. For planning purposes, the Ontario Ministry of Finance is projecting consumer price index ("CPI") inflation to slow from 3.8 per cent in 2023 to 2.6 per cent in 2024, before returning to the Bank of Canada's inflation rate target of 2.0 per cent in 2025. However, the future path of CPI inflation is uncertain. Elevated inflation for certain goods and services remains persistent. As well, risks to global supply chains have risen in recent months, impacting shipping costs and delivery times. Private-sector economists have a wide range of views, with forecasts for 2024 inflation ranging from 1.8 per cent to 3.0 per cent.

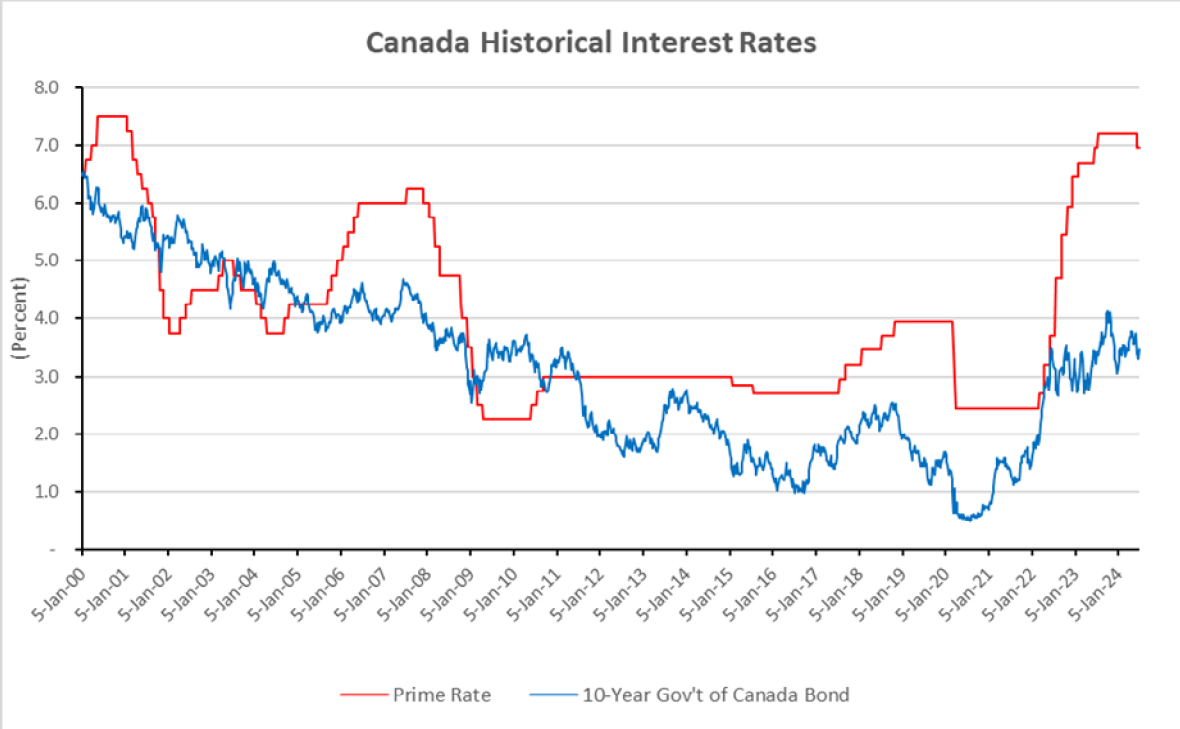
Federal carbon tax policy has contributed to inflation. The Bank of Canada has estimated that eliminating the carbon tax could create a one-time drop in inflation of 0.6 percentage points in Canada. On April 1, the federal carbon tax [increased again by $15 per tonne]. According to the Bank of Canada, [this increase] of the carbon tax would raise year-over-year inflation by roughly 0.1 percentage points.

Risks to the Outlook

Consumer price inflation has continued to ease in many jurisdictions, but measures of core inflation, which adjust for more volatile components, remain elevated. The outlook for inflation remains a key source of uncertainty for the global economy as well as for Canada and Ontario. Although several major central banks, including the Bank of Canada and the U.S. Federal Reserve, have signaled that they have likely concluded their recent cycles of interest rate increases, a significant downside risk is that they may maintain higher interest rates for longer if they judge it necessary to ensure the return of inflation to the target rate. Conversely, an upside risk for the economy is that inflation normalizes more rapidly than expected, allowing for a quicker easing of monetary policy. Economic

growth in the United States has proven surprisingly resilient in the face of significant monetary policy tightening, including strong consumer demand and buoyant labour markets. Continued economic resilience in the United States represents an upside risk to the Ontario economy, notably for growth in Ontario exports. However, the economy in the United States is exposed to significant risks as the cumulative impact of past interest rate rises are expected to weigh on aggregate demand. There is also a risk of fiscal consolidation, as ongoing sizable fiscal deficits have raised federal government debt in the United States to high levels. Geopolitical developments continue to pose a significant risk to the economic outlook. Global conflicts continue to disrupt commodity markets and pose risks to supply chains. In addition, rising trade tensions are continuing to weigh on international trade in goods and services, which could impact Ontario's key trading relationships in North America.

Chart 1



3.0 Industry Outlook

Industry Overview

Background

The Government of Ontario, through the Ministry of Energy and Electrification, sets the overall policy for the energy sector. It does this mainly through laws and regulations.

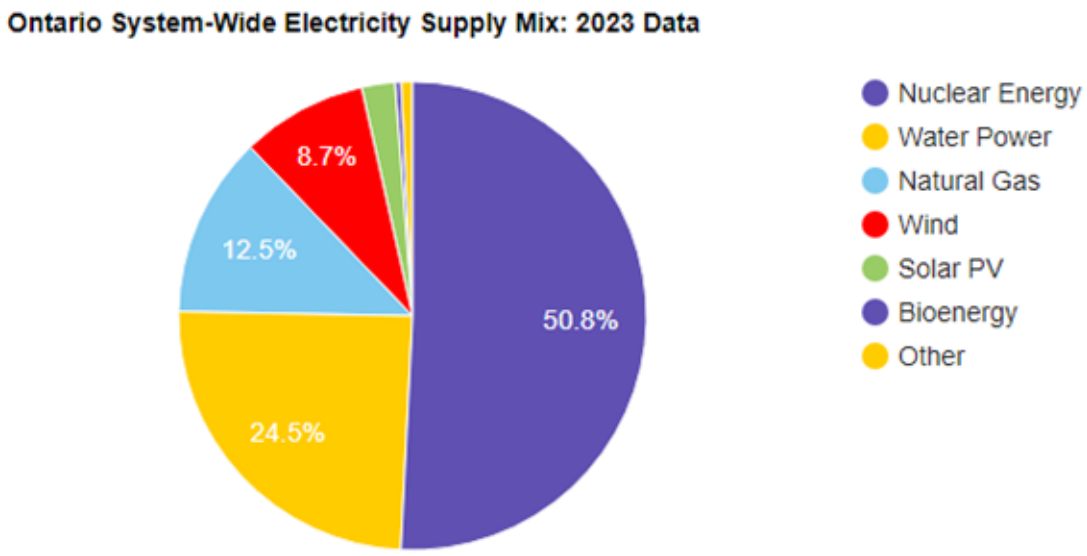
The Ontario Energy Board ("OEB") is the regulatory body that governs natural gas and electricity in Ontario. The OEB is empowered by statute to, among other things, set rates for rate-regulated entities, license market participants, approve applications for consolidations of Local Distribution Companies, approve transmission line construction, establish and enforce the rules for energy companies operating in Ontario, and monitor the wholesale electricity market and the financial and operational performance of utilities.

As described on the website of the OEB, different companies and agencies play a part in ensuring that Ontario's homes and businesses have a reliable supply of electricity, including:

Generators

Generation companies produce the electricity we use. They include facilities powered by nuclear, hydro, natural gas, wind and solar sources. The largest generator is Ontario Power Generation. Ontario's current power generation mix is as follows:

Chart 2



Transmitters

Once electricity is generated, it is relayed across Ontario on high-voltage transmission lines. These lines, which are mostly owned and operated by Hydro One, take power from the generator to the local utilities. There, it is put through transformers that convert it to low-voltage power and it is then sent out on distribution lines.

Distributors

Local utilities (also known as distributors) own and operate the low-voltage lines that deliver power to homes and businesses. They are also responsible for billing consumers and delivering conservation programs.

Retailers

Consumers have options regarding the retailer from whom they buy electricity. The vast majority (about 95%) of Ontarians choose to buy electricity from their local utility. If consumers do nothing, they automatically buy electricity from their local utility and their electricity rates are set by the Ontario Energy Board.

However, if consumers choose to buy electricity from a private company that sells electricity under contract (called an electricity retailer), then the consumer will pay the price that the consumer and retailer agree to in a contract. There are a number of electricity retailers offering electricity contracts to consumers across Ontario.

The Independent Electricity System Operator ("IESO")

The IESO balances the supply of and demand for electricity in Ontario. It directs the flow of electricity across the province's transmission lines, connecting generators that produce power, transmitters that send it across the province, local utilities that deliver it to homes and businesses, and industrial companies that use it in large quantities. The IESO plans the power system and makes sure Ontario has enough electricity over the long term. It also coordinates conservation efforts across the province.

Demand Forecast

According to *the Annual Planning Outlook* of the IESO dated March 2024:

Consistent with previous Annual Planning Outlooks ("APO"), the demand forecast continues to show steady demand growth year over year, with total demand increasing 60 per cent over the next twenty-five years.

The IESO has announced plans for various procurements since the last APO that will ensure Ontario's electricity needs are met through the mid-2030s. While there is still a lot of work ahead in 2024 and beyond to deliver, progress is being made to reshape our current electricity system to meet the needs of a growing and decarbonizing economy.

Our forecasts continue to show demand will, on average, increase two per cent a year over the coming decades, from 154 TWh in 2025 to 245 TWh by 2050. This is driven primarily by economic and population growth, mining and steel industry electrification, and growth in electric vehicle industries. Daily electricity use patterns are also changing as consumers embrace electric vehicles, industry begins to electrify their processes, and local greenhouses continue to increase agricultural production. The latest forecast shows Ontario transitioning from a summer-peaking region to a dual-peaking region beginning in 2030, with summer and winter electricity peaks being comparable at approximately 27,000 MW.

While demand is growing, consumers are also playing their part. The APO forecasts that more consumers and businesses are expected to invest in energy management through increased energy efficiency standards for buildings and equipment, and participation in conservation and demand management programs, including those providing real-time demand flexibility to the grid.

Supply Outlook

Due to the efforts of power suppliers across the province and beyond, the supply outlook for Ontario has improved. Since the last outlook, the IESO has addressed capacity shortfalls that had previously been forecast for the mid-2020s due to nuclear refurbishments and retirements as well as expiring contracts. These shortfalls have been filled as a result of Resource Adequacy Framework procurements, increased conservation and demand management targets and other government initiatives. These include 1,535 MW of supply from the Expedited Long-Term RFP and Same Technology Upgrades Solicitation, with more capacity to be secured through the Long-Term 1 RFP later this year. The IESO is also set to extend the Brighton Beach Contract, and has finalized a contract with the Oneida energy storage project to come into service in 2025.

This APO reinforces the importance of a regular cadence of procurements to flexibly meet Ontario's near to long-term needs, allowing for a reassessment of needs as time progresses and to take advantage of technological advances and associated reductions in costs.

Looking ahead, the next annual Capacity Auction is scheduled for Q4 2024 and will continue to be relied upon to secure increasing amounts of capacity to meet reliability needs, with a target of 1,600 MW for the summer 2025 obligation period, and 1,000 MW for winter 2025-2026. The IESO will increase the minimum target capacity for future auctions from no less than 500 MW to no less than 1,000 MW, to set a predictable and stable marketplace. Medium-term procurements to reacquire existing resources with expiring contracts will continue to be executed in accordance with the Resource Adequacy Framework.

Over the 2030-2034 period, the APO shows an approximately 5,000 MW and 15 TWh supply shortfall emerging as a result of increasing demand and expiring contracts. The

next long-term procurement (LT2 RFP) will be launched later this year with an expected target of 5 TWh for non-emitting energy supply, with more procurements to follow.

Resurgence of Nuclear Power

After a period of decline, a resurgence of nuclear power generation activity has been evident in Ontario and worldwide, driven by clean energy mandates and geopolitical concerns regarding energy security.

Ontario's nuclear power generation refurbishment activity has increased in recent years, with between two and three units undergoing refurbishment concurrently over the summer periods. The Darlington and Bruce refurbishments are expected to be complete in 2026 and 2033, respectively, and by the end of 2033, a total of 8.4 GW of nuclear capacity will have undergone refurbishment. Bruce A Units 1 and 2 will reach the end of their contract term in December 2043.

Recent months have marked a dramatic turn-about for the fate of nuclear energy across the developed world. As the Russian invasion of Ukraine turned post-pandemic energy shortages into an energy crisis, nuclear power plants slated for closure across Europe have been given a reprieve. Japan has announced that it plans to restart many of its reactors, which have been idle since the nuclear accident at Fukushima Daiichi. France, which had launched plans to reduce its dependence on nuclear energy during President Macron's first term, reversed course and now plans to build six new reactors and a dozen more small modular reactors. The UK has launched a plan to build eight new reactors and 16 small modular reactors. Even anti-nuclear Germany has conceded to basic geopolitical energy realities and extended the life of the nation's last three operating nuclear power plants.[1]

Additionally, according to the International Energy Agency ("IEA"), in 2022 and 2023 many countries placed the phasing in or expansion of nuclear power at the centre of their strategies to reach climate policy objectives. According to the IEA, global nuclear generation will reach a new record high by 2025. Between 2024 and 2026, an additional 29 GW of new nuclear capacity is expected to come online globally, more than half of them in China and India. With new plants starting commercial operation in various regions, as well as French nuclear recovery and expected restarts in Japan, the IEA forecasts global nuclear generation will be almost 10% higher in 2026 compared to 2023. In 2025, global electricity generation from nuclear energy will have exceeded its previous record level in 2021.[2]

[1] Ted Nordhouse and Juzel Lloyd, "Nuclear Resurgence: The energy security case for nuclear power is building", Finance & Development, February 22, 2023, p.18.
[2] International Energy Agency, "Electricity 2004: Analysis and forecast to 2026", IEA Publications, January 2024, p.44.

Summary

The Ontario electrical power generation industry is highly regulated and mature in nature. The IESO's Forecasts predict that demand will, on average, increase two per cent a year over the coming decades, from 154 TWh in 2025 to 245 TWh by 2050, driven primarily by economic and population growth, mining and steel industry electrification, and growth in electric vehicle industries.

The nuclear segment of the industry has seen a recent resurgence in growth worldwide, due primarily to geopolitical concerns with energy security and carbon emissions objectives. This expected growth, and the increased demand for machinery like the large transformers required for nuclear power generation, may impact OPG's future procurement efforts.

4.0 OPG's Research and Proposed Construction Cost Escalation Rates

OPG's Proposed Construction Cost Escalation Rates

OPG provided its proposed annual construction cost escalation rates to Kroll, as summarized below:

Calendar Year	Cost Escalation Estimate
2025	4.5%
2026	4.5%
2027	4.5%
2028	4.5%
2029	4.5%
2030	4.5%
2031	4.5%

OPG selected an average long-term cost escalation rate for use in each year of its 2025-2031forecast.

Data Sources

OPG employed the following data sources in generating its annual estimates of expected power generation construction escalation:

- Statistics Canada Table 18-10-0276-01 Building construction price indexes, by type of building and division ("BCPI") - the BCPI is a quarterly data series which measures change over time in the prices that contractors charge to construct a range of new commercial, institutional, industrial and residential buildings. These buildings include six non-residential structures: an office building; a warehouse; a shopping centre; a factory; a school; and a bus depot with maintenance and repair facilities. The contractor's price reflects the value of all materials, labour, equipment, overhead and profit to construct a new building. It excludes value added taxes and any costs for land, land assembly, building design, land development and real estate fees. Data is available from 1981 to the present.

- Construction Analytics Building Cost Index ("CA") – CA is an open access website with construction escalation indices from CA itself and various third parties. CA's own building cost indices represent whole building costs in that they track the final cost of construction, which includes, in addition to costs of labor and materials and sales/use taxes, general contractor and sub-contractor margins or overhead and profit.

- Turner Building Cost Index – is a whole, non-residential building cost index determined by the following factors considered on a U.S. nationwide basis: labour rates and productivity, material prices and the competitive condition of the marketplace. For 2023, Management noted that a year-over-year ("YOY") construction cost of 6.0% was reported by Turner, driven primarily by large-scale projects.

- Rider, Levett, Bucknall ("RLB") Actual Cost Index – is based on data published in the Quarterly Cost Reports of RLB Publications. It is for non-residential buildings only and is a whole cost index. RLB's reports include cost indices for 12 U.S. cities (Boston, Chicago, Denver, Honolulu, Las Vegas, Los Angeles, New York, Phoenix, Portland, San Francisco, Seattle, Washington, DC). Management notes that RLB's Q2 2024 data indicated that the U.S. national average increase in construction costs was approximately 5.4% YOY.

- Discussions with OPG Supply Chain, Project Controls and Finance – OPG's internal feedback shows a price escalation in a range of 4.5% to 6.0% YOY for 2024.

- Discussions with, and procurement escalations provided by Aecon Group Inc. and GE Hitachi Nuclear Energy ("GEH").

5.0 Kroll's Research and Estimated Construction Cost Escalation Rates

Introduction

In addition to reviewing the data sources used by Management, Kroll reviewed various data sources to which it subscribes (Handy-Whitman, Marshall & Swift, RSMeans), together with other relevant sources available in the public domain.

For each of the following indices, Kroll calculated the annual change in construction costs, the long-term average annual change over the life of the data series, and long-term compound annual growth rate ("CAGR").

Data Sources

- Statistics Canada Table 18-10-0276-01 Building construction price indexes, by type of building and division – as mentioned previously, the BCPI is a quarterly data series which measures change over time in the prices that contractors charge to construct a range of new buildings. The contractor's price reflects the value of all materials, labour, equipment, overhead and profit to construct a new building. It excludes value added taxes and any costs for land, land assembly, building design, land development and real estate fees. Data is available from 1981 to the present. Kroll reviewed the indices for (i) non-residential, and (ii) factory building construction in Toronto for Q1 1981 through Q1 2024.

- Handy-Whitman Electric Utility Construction Cost Indices ("HW") – HW comprises detailed indices of utility construction costs for six U.S. regions. Two of these regions are adjacent to Ontario; the North Atlantic and North Central, so we selected this data as being most relevant to our analysis. HW provides annual cost indices for nuclear power plant structures and improvements, reactor plant equipment, and total nuclear production plants from 1965 through to the present.

- Construction Analytics Building Cost Index – CA's building cost indices represent whole building costs in that they track the final cost of construction, which includes, in addition to costs of labor and materials and sales/use taxes, general contractor and sub-contractor margins or overhead and profit. We selected CA's (i) non-residential buildings, and (ii) non-building infrastructure indices as the most valid comparisons for the purposes of this report. We note that CA's indices are based exclusively on U.S. data and cover the period from 2001 to the present.

- Turner Building Cost Index – is another whole building cost index determined by the following factors, considered on a U.S. nationwide basis: labour rates and productivity, material prices and the competitive condition of the marketplace. It is a

non-residential building index. Data from 2001 through 2023 was available through the Construction Analytics website.

- RLB Actual Cost Index – is based on data published in the Quarterly Cost Reports of RLB Publications. It is for non-residential buildings only and is a whole cost index. RLB's reports include cost indices for 12 U.S. cities (Boston, Chicago, Denver, Honolulu, Las Vegas, Los Angeles, New York, Phoenix, Portland, San Francisco, Seattle, Washington, DC). RLB also has a cost index for Toronto, but since Kroll does not have a subscription with RLB, we have cited RLB's U.S. data which is available through the website of Construction Analytics. Data is available from 2001 to the present.

- Mortenson Construction Cost Index ("MCCI") – the MCCI is another whole cost index, calculated quarterly by pricing a representative non-residential construction project in 7 cities throughout the United States, including Chicago, Milwaukee, Seattle, Phoenix, Denver, Portland and Minneapolis/St. Paul. Data from 2008 to 2023 was available through the Construction Analytics website.

- Bureau of Labour Statistics Producer Price Index ("PPI") – only certain PPIs provided by the Bureau of Labor Statistics ("BLS") represent whole building costs. Kroll identified two such indices, for new industrial building construction, and new non-residential building construction. To achieve an output price, BLS combines the detailed material and installation (labor and related equipment) cost data, with margin (overhead and profit) data collected monthly by BLS directly from building construction contractors. The selected PPI indices, therefore, measure changes in the input costs for these structures, along with changes in contractor markups. For industrial buildings, the index was available for 2007 to 2023, while the non-residential index was available for 2014 to 2023.

- FM Global Canada Cost Trends – FM Global publishes its semi-annual "Property Loss Prevention Data Sheets" which indicate cost trends for industrial buildings in Canada and the US. The indices for industrial buildings are designed to reflect the impact of changes made in union wage rates and published materials prices on final construction costs, not selling prices, in the non-residential construction field. For our analysis, we utilized Industrial Building Cost Trends published for Ontario from 2014 to 2023.

- Marshall & Swift Valuation Service (M&S) – the M&S costing manual is updated monthly by CoreLogic and provides estimated construction costs for various types of buildings prevailing in specified major cities throughout Canada and the US. Using M&S, we prepared construction cost trends for Heavy Industrial Manufacturing/Process buildings that are typical of specialized manufacturing processes and power or utility service plants using protected steel frames (as used in the construction of nuclear generating facilities), adjusted to Toronto costs from 2014 to 2023. MS is a total cost index.

- RSMeans Historical Cost Indices – do not measure the output price of the final cost of buildings, but instead measures the input prices paid by subcontractors for a fixed market basket of labour and materials used in constructing the building. RSMeans is specifically for non-residential buildings only. Although RSMeans is not a total cost index in that it omits contractor margins, it has the benefit of providing data for 10 Canadian cities, including Toronto. RSMeans historical cost indexes provide general indications of changes in overall construction costs in a given city over time, and for our analysis we used the trends for Toronto from 2014 to 2023.

Development of Annual Estimates

Kroll's annual forecast of power generation construction escalation considered the following factors:

- The Handy-Whitman 'total nuclear production plant' indices were the most direct comparison with OPG's budgeted capital expenditures, which will be weighted towards nuclear power. The long-term, historical average annual escalation rates (since 1965) indicated by these indices are 4.7% for the North Atlantic region and 4.6% for the North Central region, both of which are in the U.S. but adjacent to Ontario. Being the most direct comparisons and reasonably proximate to Ontario geographically, we selected a 4.6% annual construction cost escalation rate as the long-term rate to which construction cost escalation would eventually revert.

- The Handy-Whitman 'total nuclear production plant' indices spiked in 2021, but have since declined to 6.0% and 6.1% in 2023 for the North Atlantic and North Central regions respectively. We note a continuation of this normalization trend in the available 2024 data.

- Kroll identified 4 data sources which, while focused on non-residential building construction generally rather than electrical power generation, provided Toronto-specific (Statistics Canada's Table 18-10-0276-01, M&S, and RSMeans), and Ontario-specific cost escalation data (FM Global).

    - StatsCan Table 18-10-0276-01 for (i) non-residential buildings, and (ii) factory buildings, shows long-term (since 1981) average construction escalation rates of 4.2% and 4.7% respectively in Toronto. In both categories, cost escalation spiked in 2021 and 2022, but came down to 8.2% (non-residential) and 9.1% (factory)in 2023.

    - FM Global indicates an average annual growth rate of 4% in construction costs for industrial buildings in the Province of Ontario with a surge in costs observed during the past three years from 2021 through 2023., i.e. 6.2%, 12.5% and 6.3% respectively.

    - Marshall & Swift indicates an average annual growth of 4.3% in construction costs of heavy industrial buildings with protected steel frames for the past ten years.

However, this growth was not uniform over that period as a 19.4% spike occurred in 2021, followed by a 12.8% surge in costs during 2022. For 2023, however, costs cooled down with a decline of 0.7% for protected steel frame buildings.

  - RSMeans indicates a 5.3% average annual growth rate in overall construction costs for Toronto for the past nine years. The actual final RSMeans index for Toronto for 2023 is not available at the time of our analysis, but will be available in early 2025. RSMeans followed the same pattern observed for the construction indices described above, specifically, with a significant spike in annual construction costs in the most recent years.

- We considered seven additional US construction cost indices in our analysis. While these did not apply directly to electrical power generation, they had the advantage of representing whole building costs in that they include general contractor and sub-contractor margins or overhead and profit.

- The general resurgence of nuclear power construction worldwide, and resulting increased demand and longer lead times for related plant equipment.

- Discussions with OPG Supply Chain, Project Controls and Finance. OPG's internal feedback shows a price escalation in a range of 4.5% to 6.0% YOY for 2024.

- Our own discussions with suppliers of nuclear power plant machinery and equipment.

Refer to Exhibit 1.0 for a summary of the average annual long-term escalation rates for 14 relevant indices and Exhibit 2.0 for the annual escalation rates of these same indices over the last 10 years. Please note that the annual data for certain indices in Exhibit 2.0 to which Kroll subscribes, have been redacted to remain in compliance with the terms of our subscription agreements.

In developing our forecasts of power generation construction cost escalation rates, Kroll gradually tapered its forecast rates in 2025 and 2026 down toward the expected long-term average.

Our estimates of annual forecast power generation construction cost escalation rates are set out in the table below:

Conclusion

Calendar Year	Forecast Construction Cost Escalation Rate (Kroll)
2025	5.5%
2026	5.0%
2027	4.6%
2028	4.6%
2029	4.6%
2030	4.6%
2031	4.6%
CAGR	4.8%

6.0 Conclusions

Summary Conclusions

Based on the information and analysis summarized in this report, it is our view that OPG's annual forecast rates are reasonable and supported by market data. Kroll's forecast construction cost escalation rates do not differ materially from those of Management and are summarized below:

Calendar Year	Forecast Construction Cost Escalation Rate (OPG)	Forecast Construction Cost Escalation Rate (Kroll)	Difference
2025	4.5%	5.5%	1.0%
2026	4.5%	5.0%	0.5%
2027	4.5%	4.6%	0.1%
2028	4.5%	4.6%	0.1%
2029	4.5%	4.6%	0.1%
2030	4.5%	4.6%	0.1%
2031	4.5%	4.6%	0.1%
CAGR	4.5%	4.8%	0.3%

We reserve the right, but will be under no obligation, to review all calculations referred to in this report and, if considered necessary by us, to revise our estimates in the light of any new facts, trends or changing conditions existing at any date prior to or at the Effective Date, which become apparent to us subsequent to the date of this report.

The engagement of, and compensation for, Kroll and its employees was not contingent on the development or reporting of predetermined analyses that favors the cause of the client; the amount of the estimates; the attainment of stipulated results; nor the occurrence of a subsequent event directly related to the intended use of this report.

This report represents Kroll's impartial and unbiased analysis, estimates, and conclusions limited only by the Terms and Conditions which were part of our Letter of Engagement, and the Assumptions and Limiting Conditions which are part of this report.

7.0 Assumptions and Limiting Conditions

General Statement of Assumptions and Limiting Conditions

1. To the best of our knowledge and belief, the statements of facts contained in this report, upon which the analysis and conclusion(s) expressed are based, are true and correct. Information, estimates and opinions furnished to us and contained in the report or used in the formation of the conclusion(s) were obtained from sources considered reliable and believed to be true and correct. However, no representation, liability or warranty for the accuracy of such items is assumed by or imposed on us, and is subject to corrections, errors, omissions and withdrawal without notice.

2. The prospective and historical information used for this analysis has not been subjected to any auditing or verification procedures and we express no assurance of any kind on it. The Parties have advised us that they consider the data used to be accurate, and that no information known to them conflicts with the data or resulting use of such data in this analysis.

3. The analysis may not be used in conjunction with any other appraisal or study. The conclusion(s) stated herein is/are based on the program of utilization described in the report and may not be separated into parts. The report was prepared solely for the purpose, function and party so identified in the report. The report may not be reproduced, in whole or in part, and the findings of the report may not be used by a third party for any purpose, without the express written consent of Kroll.

4. No change of any item in any of the report shall be made by anyone other than Kroll and we shall have no responsibility for any such unauthorized change.

5. We are not required to give testimony or be in attendance at any court or administrative proceedings with reference to the analysis and conclusion(s) herein unless additional compensation is agreed to, and prior arrangements have been made.

6. The working papers for this engagement are being retained in our files and are available for your reference. We would be available to support our conclusion(s) should this be required. Those services would be performed for an additional fee.

7. Neither all nor any part of the contents of the report shall be disseminated or referred to the public through advertising, public relations, news or sales media, or any other public means of communication or referenced in any publication, including any private or public offerings including but not limited to those filed with the Securities and Exchange Commission or other governmental agency, without the prior written consent and approval of the review by Kroll.

8. This analysis is based on historical and prospective financial statements. Some assumptions or projections inevitably will not materialize, and unanticipated events and circumstances may occur during the forecast period. Thus, variations could be material and have an impact on the conclusion(s) stated herein.

8.0 Exhibits

Ontario Power Generation Inc. **Exhibit 1.0**

Estimation of Annual Electrical Power Generation Construction Costs

As of August 1, 2024

Summary of Long-Term Average Construction Cost Escalation Rates

Ref #	Data Source	Description	Data Period	Geography	CAGR	Average Annual Δ
1	Statistics Canada - Table 18-10-0276-01	Non-Residential Buildings	1981 - Present	Toronto	4.3%	4.2%
2	Statistics Canada - Table 18-10-0276-01	Factory Buildings	1981 - Present	Toronto	4.8%	4.7%
3	Handy-Whitman Electric Utility Construction Cost Indices	Nuclear Production Plant	1965-2023	U.S. North Atlantic Region	4.7%	4.7%
4	Handy-Whitman Electric Utility Construction Cost Indices	Nuclear Production Plant	1965-2023	U.S. North Central Region	4.5%	4.6%
5	Construction Analytics Building Cost Index	Non-Residential Buildings	2001 - 2023	U.S.	4.3%	4.4%
6	Construction Analytics Building Cost Index	Non-Building Infrastructure	2001 - 2023	U.S.	4.3%	4.4%
7	Turner Building Cost Index	Non-Residential Buildings	2001 - 2023	U.S.	3.7%	3.8%
8	Rider Levett Bucknall Actual Cost Index	Non-Residential Buildings	2001 - 2023	U.S.	4.3%	4.3%
9	Mortenson Construction Cost Index	Non-Residential Buildings	2009 - 2023	U.S.	4.1%	4.2%
10	Bureau of Labor Statistics Producer Price Index	Industrial Buildings	2007-2023	U.S.	3.9%	4.2%
11	Bureau of Labor Statistics Producer Price Index	Non-Residential Buildings	2014-2023	U.S.	4.9%	5.3%
12	FM Global Property Loss Prevention Data Sheets	Industrial Buildings	2013-2023	Ontario	4.0%	4.0%
13	Marshall & Swift Heavy Industrial Buildings	Protected Steel Frame	2014-2023	Toronto	4.1%	4.3%
14	RSMeans Historical Cost Indexes	Overall Construction Costs	2014-2022	Toronto	5.2%	5.3%
15	All Items CPI	Inflation	1971 - Present	Toronto	4.1%	4.1%
	Average (excluding All Items CPI)				4.4%	4.4%
	Median (excluding All Items CPI)				4.3%	4.4%

Ontario Power Generation Inc. **Exhibit 2.0**

Estimation of Annual Electrical Power Generation Construction Costs

As of August 1, 2024

Summary of 2014-2023 Annual Construction Cost Escalation Rates

	Ref #	Source	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	1	Statistics Canada - Toronto Non Residential Buildings	1.4%	1.9%	2.9%	3.2%	4.6%	3.8%	2.6%	9.6%	16.2%	8.2%
	2	Statistics Canada - Toronto Factory Buildings	1.3%	1.7%	3.7%	3.7%	5.1%	4.6%	2.9%	12.4%	18.7%	9.1%
(1)	3	Handy-Whitman - Nuclear Production Plant North Atlantic										
(1)	4	Handy-Whitman - Nuclear Production Plant North Central										
	5	Construction Analytics - Non Residential Buildings	3.7%	3.4%	3.9%	3.9%	5.5%	4.5%	2.4%	8.3%	12.4%	5.4%
	6	Construction Analytics - Non Building Infrastructure	2.7%	-1.2%	-1.5%	2.1%	5.1%	4.0%	-0.7%	8.0%	17.4%	6.4%
	7	Turner Building Cost Index	4.3%	4.6%	4.8%	5.0%	5.7%	5.4%	1.8%	1.9%	8.1%	6.0%
	8	Rider Levett Bucknall Actual Cost Index	4.3%	5.2%	5.5%	4.5%	4.6%	5.5%	3.5%	4.8%	8.1%	6.9%
	9	Mortenson Construction Cost Index	3.8%	2.7%	3.5%	3.4%	7.4%	2.2%	1.9%	16.0%	11.3%	3.1%
	10	Bureau of Labor Statistics - Industrial Buildings	1.9%	2.2%	0.0%	3.9%	5.9%	4.5%	2.0%	13.4%	20.4%	0.4%
	11	Bureau of Labor Statistics - Non Residential Buildings		1.0%	1.3%	3.5%	5.2%	3.8%	1.1%	15.2%	18.2%	-1.2%
(1)	12	FM Global Canada Cost Trends - Ontario Industrial Buildings										
(1)	13	Marshall & Swift - Toronto Heavy Industrial with Protected Steel Frame										
(1)	14	RSMeans Historical Cost Indexes - Toronto Overall Construction										
(2)	15	All Items CPI - Toronto	2.5%	1.5%	2.1%	2.1%	2.5%	2.0%	0.3%	2.9%	6.5%	4.2%
		Average (excluding All Items CPI)	2.2%	2.2%	2.4%	2.9%	4.8%	3.9%	2.6%	10.2%	13.1%	4.8%
		Median (excluding All Items CPI)	1.9%	2.0%	3.0%	3.5%	5.1%	3.9%	2.2%	9.7%	12.7%	6.0%

Notes

(1) Due to the terms of Kroll's third-party data subscription agreements, we cannot disclose annual inflation data for the noted series. This data is included in the calculation of our averages and medians, however.

(2) Toronto All Items CPI presented for comparison purposes.

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About Kroll

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CCC Interrogatory #016

Interrogatory

Reference:
Exhibit A2, Tab 2, Schedule 1, Attachment 2, p. 9

Preamble:

OPG also begins support of new nuclear in Saskatchewan and Alberta, and other international jurisdictions including Poland, UK, and beyond through Laurentis Energy Partners.

Question(s):

Please explain whether, and if so how, OPG accounts for the costs and revenues that are associated with projects outside of Ontario in its revenue requirement. Please comment on the materiality of any such work outside of Ontario.

Response

New nuclear work outside of Ontario occurs through OPG's unregulated affiliates. As this work is unregulated, OPG declines to comment on its materiality. Refer to Ex. L-G2-SEC-202 for an explanation of the treatment of the associated costs and revenues in this Application.

SEC Interrogatory #023

Interrogatory

Reference:
A2-2-1, Attachment 1, p. 9

Question(s):

OPG's Business Plan notes that it expects to receive an equity injection of about $1Bn in late 2025, and that "[u]nder the anticipated terms of the equity injection, associated dividends would be in-kind during the business plan period."

a) Did the Province make the referenced equity injection?

b) What is meant by the associated dividends would be "in-kind"?

Response

a) Yes.

b) Dividends being in-kind means that, when declared, they are paid either through the issuance of additional shares or by increasing the redemption price of the shares, rather than in cash.

SEC Interrogatory #024

Interrogatory

Reference:
A2-3-1, Attachment 5, p. 2

Preamble:

Morningstar DBRS states: "The Company is currently exploring additional credit supportive funding sources, which would reduce its debt needs."

Question(s):

a) Please provide details of what credit supportive funding OPG is exploring and its status.

b) Is OPG currently investigating further CIB funding? If so, please provide details of all discussions with the CIB related to potential equity and/or debt funding.

Response

a) Ex. A2-2-1, Section 3.3 discusses the main non-debt (i.e., credit supportive) funding sources for OPG at the time the Application was filed. This includes the Concurrent Cost Recovery mechanism pursuant to O. Reg. 53/05 (which is reflected in this Application), a then anticipated shareholder equity injection from the Province of Ontario ("Province"), the DNNP equity partnership through DNNP LP, the proposed increase in the equity portion of OPG's deemed capital structure in this proceeding, and the availability of federal Clean Electricity Investment Tax Credits ("CEITCs").

   Since the Application was prepared, as assumed in OPG's 2025-2031 Business Plan, OPG has received an initial tranche of the $5 billion committed equity injection from the Province and is expected to receive further proceeds in a staged manner over the remainder of the 2025-2027 period; OPG has transferred the requisite assets related to DNNP to DNNP LP, a subsidiary of Canada Growth Fund and a subsidiary of Building Ontario Fund have acquired minority interests in DNNP LP and OPG has been reimbursed by DNNP LP for its DNNP construction progress costs (Ex. L-A1-CCC-010); and federal legislation implementing the CEITCs has received Royal Assent (Ex. L-F4-CCC-084).

b) No.

SEC Interrogatory #025

Interrogatory

Reference:
A2-2-1, Attachment 1

Question(s):

Please provide a full reconciliation between:

a) The 2025-2031 OPG nuclear and DNNP OM&A as set out in the Business Plan (A2-2-1, Attachment 1, p.34), and the OM&A included in the application (F2-1-1 Table 1a).

b) The 2025-2031 OPG nuclear and DNNP capital expenditures as set out in the Business Plan (A2-2-1, Attachment 1, p.38) and in the Application (D2-1-2, Table 1).

c) The 2025-2031 OPG support services OM&A as set out in the Business Plan (A2-2-1, Attachment 1, p.34) and in the Application (F3-1-1, Table 1).

d) The 2025-2031 OPG support services capital expenditures as set out in the Business Plan (A2-2-1, Attachment 1, p.38) and in the Application (D3-1-1, Table 1).

e) The 2025-2031 OPG centrally held OM&A costs as set out in the Business Plan (A2-2-1, Attachment 1, p.34) and in the Application (F4-4-1, Table 1).

For each reconciliation, if they are not the same, please explain all differences.

Response

a), c) and e) Refer to Attachment 1.

b) and d) Refer to Attachment 2.

Table 1 - Ex.L-A2-SEC-25-(a)

Operating Costs Summary - OPG Nuclear Facilities and DNNP facilities ($M) - Business Plan Reconciliation

		Ex. F2-1-1 Table 1a and Ex. F2-1-1 Table 1b							Ex. A2-2-1, Attachment 1, P. 34							Variance						
Line No.	Cost Item	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)
	OM&A:																					
1	**Base OM&A**[1]																					
2	**Project OM&A**	75.6	73.3	76.1	82.4	84.0	84.8	83.2	75.5	73.3	76.1	82.4	84.0	84.8	83.2	0.1	(0.0)	0.0	(0.0)	0.0	0.0	0.0
3	**Outage OM&A**	127.0	209.4	223.7	112.7	219.1	121.7	190.9	127.0	209.4	223.7	112.7	219.1	121.7	190.9	0.0	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)
4	**Pickering Cyclical Maintenance OM&A**	0.0	25.0	168.4	160.9	168.9	169.9	106.6	0.0	25.0	168.4	160.9	168.9	169.9	106.6	0.0	0.0	0.0	0.0	(0.0)	(0.0)	(0.0)
5	**Subtotal OPG Nuclear and DNNP Facilities OM&A**	202.6	307.7	468.2	356.1	472.0	376.5	380.7	202.5	307.7	468.2	356.1	472.0	376.5	380.7	0.1	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.0)
6	**Darlington Refurbishment OM&A**	10.5	1.8	0.0	0.0	0.0	0.0	0.0	10.5	1.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	**Darlington New Nuclear OM&A**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**DNNP Operational Readiness**[4]	17.3	28.8	45.9	46.3	40.0	40.2	0.0	13.3	28.8	45.9	46.4	41.9	46.3	14.9	**4.0**	(0.0)	(0.0)	**(0.1)**	**(1.9)**	**(6.0)**	**(14.9)**
9	**Other New Nuclear OM&A**[5]	62.1	136.4	0.0	0.0	0.0	0.0	0.0	62.1	136.4	4.2	4.3	4.4	4.4	3.6	0.0	0.0	**(4.2)**	**(4.3)**	**(4.4)**	**(4.4)**	**(3.6)**
10	**Pickering Refurbishment Feasibility Study**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Pickering Refurbishment OM&A**	0.0	4.2	100.3	94.1	84.9	52.7	46.5	0.0	4.2	100.3	94.1	84.9	52.7	46.5	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0
12	**Allocation of Corporate Costs**[2]																					
13	**Allocation of Centrally Held Costs**[2]																					
14	**Asset Service Fees**[3]																					
15	**Subtotal Other OM&A**	89.9	171.2	146.2	140.4	124.9	92.9	46.5	85.9	171.2	150.5	144.8	131.2	103.4	65.0	4.0	(0.0)	(4.2)	(4.4)	(6.3)	(10.5)	(18.5)
16	**Total OPG Nuclear and DNNP Facilities OM&A**	292.5	478.9	614.4	496.5	596.8	469.4	427.2	288.4	478.9	618.7	500.9	603.1	479.9	445.7	4.1	(0.0)	(4.2)	(4.4)	(6.3)	(10.5)	(18.5)

Notes:

1 Base OM&A costs in Ex. F2-1-1 Table 1a and 1b are a functional view comprised of Station direct OM&A costs and Operations & Project Support allocated costs to OPG Nuclear and DNNP Facilities. Nuclear Base OM&A and Operations & Project Support OM&A costs in Ex. A2-2-1, Att. 1, p. 34 are presented in an organizational view. Additionally, Ex. A2-2-1, Att. 1, p. 34 reports OM&A costs for Total OPG, whereas Ex. F2-1-1 Table 1a and 1b reflects the OPG Nuclear and DNNP Facilities' portion of such costs. For these reasons, the amounts are not comparable.

2 Ex. A2-2-1, Att. 1, p. 34 reports these OM&A costs for Total OPG and is therefore not comparable to Allocation Corporate Costs and Allocation of Centrally Held Costs that represent the OPG Nuclear and DNNP Facilities' portion of such costs. Refer to parts c) and e) of Ex. L-A2-SEC-025 for Total OPG Corporate Costs and Centrally Held Costs reconciliation.

3 Asset Service Fees represent inter-segment charges for the use of certain OPG capital assets by operating busienss units and are therefore not reflected in that form in the consolidated OPG OM&A costs at Ex. A2-2-1, Att. 1, p. 34. Refer to Ex. F3-2-1 for further information on Asset Service Fees.

4 DNNP Operational Readiness OM&A costs at Ex. A2-2-1, Att. 1, p. 34 include those associated with potential DNNP Units 2-4 , which are not included in the proposed DNNP Facilities' revenue requirement (2027-2031). Refer to Ex. D2-4-1 for further information on the DNNP. The 2025 variance is attributable to the inadvertant use of a different forecast in the Application.

5 As discussed in Ex. F2-1-1, Section 5.1, the proposed revenue requirements do not include any OM&A costs related to potential new nuclear generation.

Table 2 - Ex.L-A2-SEC-25-(c)

		Corporate Support & Administrative Groups OM&A Costs - OPG ($M)						
Line No.	Cost Item	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Corporate Support & Administrative Groups- Total OPG (Ex. F3-1-1 Table 1, line 10)	519.9	546.9	554.9	555.3	578.1	597.8	638.0
2	Support Services OM&A- Total OPG (Ex. A2-2-1, Att. 1, p. 34)	520.3	556.5	568.3	568.9	592.4	612.7	653.5
3	**Variance**	**(0.5)**	**(9.6)**	**(13.4)**	**(13.6)**	**(14.3)**	**(14.8)**	**(15.5)**
	Breakdown of Variance:							
4	Fitness for Duty costs- Presented in Nuclear Base OM&A in Ex. F2-1-1, Table 1a	(4.5)	(4.7)	(4.4)	(4.4)	(4.4)	(4.4)	(4.4)
5	DNNP Information Technology Projects for potential Unit 2-4 operational readiness- Not included in DNNP Facilties' revenue requirement	0.0	0.0	0.0	(0.1)	(0.6)	(1.0)	(1.4)
6	Real Estate operating costs included in Asset Service Fees- Ex. F3-2-1	(4.1)	(5.0)	(9.0)	(9.1)	(9.3)	(9.5)	(9.6)
7	Variance relates to an error identified during the preparation of the Application	8.1	0.0	0.0	0.0	0.0	0.0	0.0
8	**Total**	**(0.5)**	**(9.7)**	**(13.3)**	**(13.6)**	**(14.3)**	**(14.8)**	**(15.5)**

Table 3 - Ex.L-A2-SEC-25-(e)

Centrally Held Costs ($M)

OPG

		Ex. F4-4-1 Table 1							Ex. A2-2-1, Attachment 1, pg 34							Variance						
Line No.	Corporate Costs	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)
1	**Pension/OPEB Related Accrual Costs**[1]	(227.5)	(210.7)	(194.0)	(212.6)	(225.3)	(223.8)	(226.6)	(191.9)	(210.7)	(194.0)	(212.6)	(225.3)	(223.8)	(226.6)	(35.6)	(0.0)	(0.0)	0.0	(0.0)	0.0	0.0
2	**OPG-Wide & Nuclear Insurance**	52.4	51.0	65.6	68.4	71.3	79.7	91.2	52.4	51.0	65.6	68.4	71.3	79.7	91.2	(0.0)	0.0	0.0	(0.0)	(0.0)	(0.0)	(0.0)
3	**Performance Incentives**	48.3	45.1	47.0	50.6	52.5	53.1	54.6	48.3	45.1	47.0	50.6	52.5	53.1	54.6	0.0	0.0	0.0	(0.0)	(0.0)	0.0	0.0
4	**IESO Non-Energy Charges**[2]	65.1	48.2	31.9	53.8	45.4	53.6	62.0	65.1	48.2	31.9	53.8	45.4	53.6	62.0	0.0	0.0	(0.0)	(0.0)	0.0	(0.0)	(0.0)
5	**Other**[3]	27.5	24.0	28.3	19.7	1.1	24.5	24.9	35.5	24.0	28.3	19.7	1.1	24.5	24.9	(8.0)	0.0	(0.0)	(0.0)	0.0	0.0	0.0
6	**Total**	**(34.3)**	**(42.4)**	**(21.2)**	**(20.1)**	**(55.0)**	**(12.9)**	**6.1**	**9.4**	**(42.4)**	**(21.1)**	**(20.1)**	**(55.0)**	**(13.0)**	**6.1**	**(43.7)**	**0.0**	**(0.0)**	**(0.0)**	**0.0**	**0.0**	**0.0**

Notes:

1 The variance is due to the Application reflecting the 2025 pension and OPEB costs based on available actual acturial assumptions for the year.

2 These costs are presented against the Electricity Generation Revenue line in Ex. A2-2-1, Attachment 1, p. 33.

3 The variance is due to presentation of these costs within OPG Nuclear Faciliites (Ex. F2-1-1, Table 1) and regulated hydroelectric (Ex. F1-1-1, Table 1) Base OM&A costs in 2025.

Table 1 -Ex.L-A2-SEC-25-(b)

Capital Expenditures Summary - OPG Nuclear Facilities ($M)

		Ex. D2-1-2, Table 1							A2-2-1, Attachment 1, P. 38							Variance						
Line No.	Category	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)
1	Nuclear Operations Capital	579.7	861.2	1,053.1	1,004.8	1,138.7	1,154.1	836.6	579.7	861.2	1,053.1	1,004.8	1,138.7	1,154.1	836.6	0.0	0.0	(0.0)	0.0	(0.0)	(0.0)	(0.0)
2	Darlington Refurbishment Program	835.2	392.0	0.0	0.0	0.0	0.0	0.0	835.2	392.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	0.0	0.0	0.0	0.0	0.0
3	Pickering Refurbishment Program[1]	1,500.0	3,045.6	3,473.2	3,607.6	3,578.3	2,681.4	1,860.5	1,500.0	2,953.7	3,667.7	3,676.5	3,480.4	2,627.8	1,858.6	0.0	91.8	(194.5)	(68.9)	97.9	53.6	2.0
4	Total OPG Nuclear Facilities Capital	2,914.9	4,298.8	4,526.3	4,612.4	4,717.0	3,835.5	2,697.2	2,914.8	4,206.9	4,720.8	4,681.3	4,619.1	3,781.9	2,695.2	0.0	91.8	(194.5)	(68.9)	97.9	53.6	2.0
5	DNNP Capitalized Fuel[2]	0.0	0.0	0.0	0.0	0.0	78.1	25.0	0.0	0.0	0.0	0.0	0.0	78.1	28.5	0.0	0.0	0.0	0.0	0.0	0.0	(3.5)

Notes:

1 The variance reflects final Pickering Refurbishment Program RQE capital flows available after finalization of the business plan.

2 The variance in 2031 relates to an error identified during preparation of the Application. The DNNP Facilities' revenue requirement reflects, through the Nuclear Fuel Service Fee, the resulting lower capitalized nuclear fuel costs.

Table 2 -Ex.L-A2-SEC-25-(d)

Capital Expenditures Summary - Support Services ($M)

		Ex. D3-1-1, Table 1							A2-2-1, Attachment 1, pg. 38							Variance						
Line No.	Support Services	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)
1	IT Portfolio and Enterprise System Modernization Projects[1]	115.2	155.0	181.9	149.9	136.6	135.9	122.0	86.7	155.0	181.9	149.9	136.5	135.9	122.0	28.5	(0.0)	(0.0)	(0.0)	0.0	(0.0)	(0.0)
2	Real Estate	36.1	76.6	102.4	41.8	42.9	47.7	31.2	36.1	76.6	102.4	41.8	42.9	47.7	31.2	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
3	Subtotal	151.3	231.7	284.3	191.7	179.5	183.6	153.2	122.8	231.7	284.3	191.7	179.4	183.6	153.2	28.5	(0.0)	(0.0)	(0.0)	0.0	(0.0)	(0.0)
4	Microsoft Enterprise Agreement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Corporate Headquarters[2]	85.3	0.0	0.0	0.0	0.0	0.0	0.0	80.8	0.0	0.0	0.0	0.0	0.0	0.0	4.5	0.0	0.0	0.0	0.0	0.0	0.0
6	Subtotal	85.3	0.0	0.0	0.0	0.0	0.0	0.0	80.8	0.0	0.0	0.0	0.0	0.0	0.0	4.5	0.0	0.0	0.0	0.0	0.0	0.0
7	DNNP Operational Readiness Technology Projects (DNNP Asset Service Fee)[3]	25.4	45.3	28.7	22.4	16.6	7.5	5.8	24.3	36.1	28.3	22.6	19.8	16.4	19.5	1.1	9.3	0.4	(0.1)	(3.2)	(8.9)	(13.7)
8	Total	262.1	277.0	313.0	214.1	196.0	191.1	159.0	227.9	267.7	312.6	214.3	199.2	200.0	172.7	34.2	9.2	0.4	(0.2)	(3.2)	(9.0)	(13.7)

Notes :

1 The variances reflect the presentation of certain OM&A cloud computing arrangements as capital expenditures in the Application, for the reasons set out in Ex. L-D3-SEC-120, part c).

2 The 2025 variance is attributed to the inadvertant use of a different forecast in the Application.

3 In addition to Note 1, the variances are attributed to the exclusion of potential Units 2-4 DNNP Operational Readiness Technology Projectd costs from DNNP Facilities' revenue requirement. Refer to Ex. D2-4-1.

Table 3 -Ex.L-A2-SEC-26-(c)

Capital Expenditures Summary - Regulated Hydroelectric and Hydro Common ($M)

		Ex. D1-1-1 Table 1							Ex. A2-2-1, Attachment 1, P. 38							Variance						
Line No.	Category	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	2025 Budget	2026 Budget	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)
1	Total Regulated Hydroelectric Capital	835.4	984.2	880.9	920.4	1,025.0	1,001.2	946.6	835.4	983.1	877.0	914.3	999.1	966.8	918.6	0.0	1.1	3.9	6.1	25.9	34.4	28.0
2	Chat Falls Expansion [1]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	1.1	3.9	6.1	25.9	34.5	28.0	0.0	(1.1)	(3.9)	(6.1)	(25.9)	(34.5)	(28.0)
3	Total Hydro Common Capital[2]	14.4	13.6	7.3	0.1	0.0	0.0	-	-	-	-	-	-	-	-	14	14	7	0	0	0	-

Notes:

1 Chat Falls Expansion is included in line 1 of Ex. D1-1-1, Table 1.

2 Ex. A2-2-1, Attachment 1, p. 38 does not separately show Hydro Common Capital, which is held within the "Other" line.

SEC Interrogatory #026

Interrogatory

Reference:
A2-2-1, Attachment 1

Question(s):

With respect to regulated hydroelectric included in the Business Plan:

a) The Business Plan includes OPG regulated hydroelectric OM&A as part of the 'Renewable Generation'. Please provide a breakdown of the Renewable Generation OM&A costs between regulated hydroelectric and non-regulated hydroelectric.

b) Based on the Business Plan OM&A costs, please provide the total regulated hydroelectric OM&A for each year between 2025-2031.

c) Please provide a full reconciliation between the 2025-2031 OPG hydroelectric capital expenditures as set out in the Business Plan (A2-2-1, Attachment 1, p.38), and the capital expenditures included in the Application (D1-1-1, Table 1). If they are not the same, please explain all differences.

d) Please provide a full reconciliation between the 2025-2027 OPG hydroelectric OM&A as set out in the Business Plan (A2-2-1, Attachment 1, p.34), and the OM&A included in the Application (F1-1-1 Table 1a). If they are not the same, please explain all differences.

Response

a) and b)

OPG confirms that the regulated hydroelectric OM&A costs provided in Ex. F1-1-1 are consistent with OPG's 2025-2031 Business Plan (Ex. A2-2-1, Attachment 1, p. 34). OPG declines to provide the breakdown of Renewable Generation OM&A costs between regulated and non-regulated hydroelectric facilities as the latter is not relevant to the approvals sought in this Application. For clarity, the Renewable Generation line in Ex. A2-2-1, Attachment 1 represents an organizational view of the costs that is not directly comparable to the presentation of costs sought in this Application. For example, the Energy Markets department reports into the Renewable Generation organization and is included in the Renewable Generation

line in the business plan but is presented as an Operations support function in the Application as part of the fully allocated view for revenue requirement purposes.

Please refer to Ex. F1-1-1 for the total regulated hydroelectric OM&A costs for 2025-2027. OPG declines to provide the requested information for the outer years of the period (i.e., 2028-2031) as this information is not relevant under the proposed regulated hydroelectric rate-setting methodology (Ex. A1-3-2, Section 2.0). Outside of the C-factor, OPG's proposed hydroelectric rate-setting methodology is based on a detailed review of the 2027 test-year (Ex. A1-3-2, Section 2.2). Beyond the 2027 test year, regulated hydroelectric revenue will be determined formulaically by the proposed annual adjustment mechanism outlined in Ex. A1-3-2, Section 2.3.

c) Refer to Ex. L-A2-SEC-025, Attachment 2.

d) See part a).

SEC Interrogatory #027

Interrogatory

Reference:
A2-2-1, Attachment 2, p. 9

Preamble:

The 2025-2031 Business Plan Assumptions states that "OPG also begins support of new nuclear in Saskatchewan and Alberta, and other international jurisdictions including Poland, UK, and beyond through Laurentis Energy Partners."

Question(s):

Please explain how the revenue and costs for OPG's support for new nuclear has been incorporated into the proposed revenue requirement between 2027 and 2031, and specify the specific revenues and costs.

Response

Refer to Ex. L-G2-SEC-202.

Board Staff Interrogatory #010

Interrogatory

Reference:
Ref 1: Exhibit A2 / Tab 1 / Schedule 1 / Attachment 4
Ref 2: Exhibit A2 / Tab 3 / Schedule 1 / Attachments 1-13

Preamble:

OPG has provided its Management's Discussion & Analysis and audited financial statements, as at and for the year ended December 31, 2024.

OPG has also provided its rating agency reports.

Question(s):

a) Please provide OPG's Management's Discussion & Analysis and audited financial statements, as at and for the year ended December 31, 2025, when available.

b) Please provide any rating agency reports that have been issued since OPG filed its current application in December 2025.

Response

a) See Attachment 1.

b) In previous payment amounts applications, OPG has typically filed annual credit rating agency reports. In addition to the S&P report dated April 2, 2026 and DBRS press release dated April 10, 2026 included as Attachment 2 and 3, as part of this response, OPG has provided credit rating agency issuer comment and tear sheet reports that have been received since EB-2020-0290, as Attachments 4-9.

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March 12, 2026

OPG Reports 2025 Financial Results

Darlington Refurbishment ahead of schedule and under budget; progress achieved on other major clean energy projects

Oshawa, ON – Ontario Power Generation Inc. (OPG or Company) today reported its financial and operating results for 2025, with net income attributable to the Shareholder of $1,509 million, compared to $988 million for 2024.

Darlington Nuclear Refurbishment

With careful planning and just over nine years of execution, the final unit of the Darlington Nuclear Refurbishment Project has been synchronized to the electricity grid, with high power operation achieved during final commissioning ahead of a full and safe return to service expected in March 2026, over four months ahead of schedule and under budget. Following project closeout activities, OPG expects the project to be completed approximately $150 million below the $12.8 billion budget OPG publicly committed to when construction commenced in 2016.

The project ensures that the Darlington nuclear generating station (Darlington GS) will continue to reliably produce approximately 3,500 MW of clean, cost effective electricity – enough to power more than 3.5 million homes – for at least another 30 years.

Darlington Refurbishment has created thousands of jobs for Ontarians during construction and in support of the station's extended operating lifespan. It also reinvigorated Ontario's nuclear supply chain, which is now well positioned to advance the refurbishment of the Pickering nuclear generation station (Pickering GS) and the construction of the G7's first grid-scale small modular reactor (SMR) at the Darlington New Nuclear Project (DNNP) site.

"Early, safe, and under-budget completion of this clean energy mega-project clearly demonstrates OPG's ability to manage large complex projects – and that is key as we proceed with other large infrastructure work," said Nicolle Butcher, OPG's President and CEO. "Our careful evaluation and planning of projects like these ensures long-term reliability and value for electricity consumers, while supporting the clean energy future Ontarians expect."

Pickering Nuclear Refurbishment

In November 2025, the Province of Ontario (Province) announced its approval of OPG's plan to proceed with the refurbishment of Units 5-8 at the Pickering GS.

Refurbishing the Pickering GS will secure more than 2,000 MW of clean, reliable nuclear power for Ontario for another 30-plus years, enough to power more than two million homes. Same as for the Darlington Refurbishment, OPG has released a high-confidence overall project cost estimate, based on the detailed planning and engineering completed. The approved budget to refurbish the four units is $26.8 billion, including interest, cost escalation, and contingency.

The project is expected to have a significant positive impact on Ontario's economy, creating thousands of jobs during construction, sustaining thousands of jobs during the station's extended operating life, and growing Ontario's nuclear supply chain.

"We have the talent and experience, honed during the Darlington Refurbishment and ready to transition to this project, to deliver Pickering Refurbishment within budget and make it as successful as Darlington's," said Butcher.

As planned, OPG expects to remove the four Pickering units from service at the end of the third quarter of 2026, followed by defueling of the reactors, with project execution expected to commence in January 2027. OPG and its project partners anticipate that the four-unit refurbishment will be completed by 2034, with the first unit scheduled to complete refurbishment, Unit 5, expected to return to service in 2031.

Initial Project Description for Potential New Nuclear at OPG's Wesleyville Site

In December 2025, OPG filed the Initial Project Description (IPD) for potential new nuclear generation development at its approximately 540-hectare Wesleyville site in Port Hope, Ontario with the Impact Assessment Agency of Canada. The IPD, a preliminary document that provides an overview of the proposed project, is the first step in the federal Impact Assessment process for assessing the project's potential impacts on the environment, health, social and economic conditions, and Indigenous rights, and to explore how adverse effects could be mitigated.

Since the Province asked OPG to explore opportunities for new nuclear generation at the site in early 2025, OPG has been actively engaging with Indigenous Rights-holders, the Municipality of Port Hope, stakeholders, and the public about the potential for such a project. OPG developed the IPD based on a range of potential nuclear technologies that could be deployed, with a total generating capacity of up to 10,000 MW. The IPD submission initiated the first of several opportunities for public comment in the multi-phased Impact Assessment process, which is expected to span several years.

"We are excited to take this first regulatory step as we continue our engagement on the potential for nuclear generation at our Wesleyville site in Port Hope," said Butcher. "OPG extends our thanks to Alderville, Curve Lake, Hiawatha, and Mississaugas of Scugog Island First Nations of the Williams Treaties First Nations for their substantive contribution to this document, as well as to the Municipality of Port Hope."

Meanwhile, OPG and the Municipality of Port Hope have signed a Memorandum of Understanding (MOU) aimed at collaboration through the assessment process. The MOU also includes an additional $4.5 million in growth readiness funding to Port Hope to support the community's preparation for and exploration of nuclear power. OPG is committed to ensuring that the Municipality of Port Hope is able to engage fully on behalf of its residents in the multi-year process to assess and develop the site.

Federal and Provincial Support for Nuclear Projects

As announced in October 2025, OPG secured up to $3 billion in aggregate equity financing for the four-SMR DNNP from the provincial Building Ontario Fund (BOF) and the federal Canada Growth Fund (CGF), subject to the satisfaction of certain conditions. OPG will remain the majority owner, project manager and operator of the DNNP, with the CGF and BOF acquiring minority equity interests in an OPG subsidiary formed for this purpose.

Additionally, in December 2025, the Province amended *Ontario Regulation 53/05* under the *Ontario Energy Board Act, 1998* to establish the rate-setting framework through the Ontario Energy Board (OEB) that enables OPG to enter commercial partnerships for DNNP. The amendments also permit OPG to recover, through regulated prices set for OPG's electricity generation by the OEB, interest amounts associated with expenditures on the Pickering Refurbishment and the DNNP prior to placing these assets into service.

In late 2025, the Province also committed to providing a $5 billion equity injection over the 2025-2027 timeframe toward OPG's overall financing needs. In December 2025, the Province injected $1 billion of such funding to OPG, in exchange for shares, per the arrangement.

"These credit-supportive financing instruments, which will lower costs to Ontario ratepayers in the longer term, underscore the Province's commitment to advancing nuclear energy development," said Butcher. "With demand for clean energy in Ontario poised to grow by as much as 65 per cent by 2050, the time to invest in new and renewed generation is now. These mechanisms help us to do so in a way that balances this critical need with affordability for Ontario ratepayers."

Filing of Rate Application to Support Ontario's Growing Energy Needs

In December 2025, OPG filed a comprehensive application for new regulated prices for electricity to be generated from its regulated hydroelectric and nuclear assets, including the first DNNP SMR, effective for the January 1, 2027 to December 31, 2031 period, with the OEB. This submission marks the start of a formal public review process by the OEB that is expected to continue through most of 2026.

The Province's Independent Electricity System Operator forecasts electricity demand in the province will rise significantly by 2050. As part of the Province's broader plan to ensure secure, reliable and affordable power to meet these growing needs, OPG has been tasked with refurbishing and expanding its clean electricity generating fleet. These investments and the work to deliver them underpin OPG's application for new regulated prices.

"The proposed rates in our application would help us deliver on critical investments needed to meet rising energy demand – driven by electrification, new industries, and a growing population – while ensuring transparency and public accountability through the OEB's rigorous review process, with OPG being the only generator in the province to undergo such review," said Butcher.

Frederick House Lake Dam rehabilitation

OPG has substantially completed work on the Frederick House Lake Dam rehabilitation project near Timmins, Ontario, under budget and ahead of schedule. This work will extend the dam's operating life, while continuing to uphold industry leading standards of dam and public safety.

The Frederick House Lake Dam is one of 239 dams that OPG operates across Ontario. Constructed in the 1930s, this dam has a long history of managing and storing water for hydroelectric generation at Abitibi Canyon and Otter Rapids generating stations in northeastern Ontario.

"The Frederick House Lake Dam, which is approaching 90 years in service, is a great example of the value and durability of OPG's hydroelectric assets," said Butcher. "Through continued investment in our hydroelectric fleet, we are modernizing infrastructure, improving generating capacity and realizing efficiencies to extend the life of these assets for generations to come."

Fourth quarter highlights include:

Net Income attributable to the Shareholder

Net income attributable to the Shareholder for 2025 was $1,509 million, representing an increase of $521 million compared to 2024. The increase was 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 as planned, and higher revenue as a result of higher nuclear electricity generation. The increase in earnings was partially offset by a non-recurring pre-tax loss recognized related to the sale of electricity generation and development business in the United States, which transaction closed in January 2026.

Generating and Operating Performance

Electricity generated in 2025 was 88.3 terawatt hours (TWh) compared to 82.1 TWh in 2024.

Regulated – Nuclear Generation Segment

Electricity generation from the Regulated – Nuclear Generation business segment increased by 5.0 TWh in 2025, compared to 2024, 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 unit capability rate at the Darlington GS increased from 87.0 per cent for 2024 to 97.2 per cent for 2025, primarily due to fewer unplanned outage days. The unit capability rate at the Pickering GS in 2025 was comparable to 2024.

Regulated – Hydroelectric Generation Segment

Electricity generation from the Regulated – Hydroelectric Generation business segment decreased by 1.6 TWh during 2025, compared to 2024, primarily due to lower water inflow conditions across most of Ontario during the second half of 2025.

Availability at the regulated hydroelectric stations for 2025 was comparable to 2024.

Contracted Hydroelectric and Other Generation Segment

Electricity generation from the Contracted Hydroelectric and Other Generation business segment increased by 0.6 TWh during 2025, compared to 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 for 2025 was 84.6 per cent, compared to 80.8 per cent in 2024. The increase was 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 2.2 TWh in 2025, compared to 2024, primarily due to higher demand for electricity generation from the combined cycle plants.

Thermal Availability of the generating stations in the segment for 2025 was 84.6 per cent compared to 85.1 per cent in 2024. The decrease was primarily due to planned outages for work performed to execute the IESO-awarded capacity upgrade projects, partially offset by 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 March 7, 2026, Unit 4 of the Darlington GS was synchronized to the electricity grid, with high power operation achieved during final commissioning, and is now in the final stages of a full and safe return to service in March 2026, over four months ahead of the original schedule. The return to service of Unit 4 will mark the substantial completion of the four-unit Darlington Refurbishment project, which will continue to provide at least another 30 years of approximately 3,500 MW of cost-effective, reliable and clean baseload electricity generating capacity for Ontario.

The total project completion costs for the four units, including the impacts of the COVID-19 pandemic and inflation, are expected to be approximately $150 million below the $12.8 billion budget, upon completion of project closure activities.

Pickering Refurbishment Project

On November 26, 2025, the Province announced its approval of OPG's plan to proceed with the refurbishment of Units 5 to 8 of the Pickering GS. The total budget for refurbishing the four units, including interest, cost escalation and contingency, is $26.8 billion, which represents the release-quality estimate approved by the OPG Board of Directors. The project will incorporate the benefits of experience gained through the completed refurbishment of the four units at the Darlington GS.

As planned, OPG expects to remove Units 5 to 8 of the Pickering GS from service in September 2026, followed by the defueling of the reactors, with the execution phase of the project commencing in January 2027. The first unit scheduled to complete refurbishment, Unit 5, is expected to return to service in 2031, with the overall refurbishment anticipated to be completed by 2034.

Darlington New Nuclear Project

Following the Canadian Nuclear Safety Commission's approval of the licence to construct in April 2025 and the Province'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, including interest, cost escalation and contingency.

During 2025, the project completed the baseline detailed design milestone as well as the construction of the pre-assembly building, which will support the final assembly of reactor building structural components. The project is progressing towards the construction of the Unit 1 basemat, which represents the foundation of the reactor building.

As supported by the Province, OPG also continues to advance planning and licensing activities for the three additional SMRs, with site grading activities completed in 2025. Pending provincial and regulatory approvals for the construction of these additional SMRs, 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 year ended December 31, 2025, section, *Core Business and Outlook* under the heading, *Project Excellence*.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(millions of dollars – except where noted)	**2025**	**2024**
Revenue	**8,355**	7,187
Fuel expense	**1,421**	1,049
Operations, maintenance and administration expenses	**2,816**	3,318
Depreciation and amortization expenses	**1,413**	1,270
Accretion on fixed asset removal and nuclear waste management liabilities	**1,243**	1,221
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(1,138)**	(1,102)
Other net expenses	**425**	69
Earnings before interest and income taxes	**2,175**	1,362
Net interest expense	**194**	186
Income tax expense	**453**	170
Net Income	**1,528**	1,006
Net income attributable to the Shareholder	**1,509**	988
Net income attributable to non-controlling interest [1]	**19**	18
Earnings (loss) before interest and income taxes		
Electricity generating business segments	**2,133**	1,441
Regulated – Nuclear Sustainability Services	**(94)**	(108)
Other	**136**	29
Earnings before interest and income taxes	**2,175**	1,362
Cash flow provided by operating activities	**3,708**	2,211
Capital expenditures [2]	**5,860**	3,725
Electricity generation (TWh)		
Regulated – Nuclear Generation	**38.0**	33.0
Regulated – Hydroelectric Generation	**30.9**	32.5
Contracted Hydroelectric and Other Generation [3]	**5.6**	5.0
Atura Power	**13.8**	11.6
Total OPG electricity generation	**88.3**	82.1
Nuclear unit capability rate (per cent) [4]		
Darlington GS [5]	**97.2**	87.0
Pickering GS	**96.7**	96.4
Availability (per cent) [6]		
Regulated – Hydroelectric Generation	**85.5**	85.8
Contracted Hydroelectric and Other Generation – hydroelectric stations	**84.6**	80.8
Atura Power	**84.6**	85.1

[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] Nuclear unit capability rate 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, adjusted for planned energy losses.

[5] 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.

[6] Hydroelectric Availability represents the percentage of time a generating unit at OPG's hydroelectric generating stations 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 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.

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.

OPG'S audited consolidated financial statements and Management's Discussion and Analysis as at and for the year ended December 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:

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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

DECEMBER 31, 2025

ONTARIO POWER GENERATION

2025 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, 2025. OPG's audited 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 December 2025, the OSC approved an exemption which allows the Company to continue to apply US GAAP up to January 1, 2032. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2032. For details, refer to the section, *Significant Accounting Policies and Critical Accounting Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP*. This MD&A is dated March 12, 2026.

Additional information about OPG, including the Company's Annual Information Form (AIF), 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 including timing and satisfaction of closing conditions 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), 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 and transactions, applications to the Ontario Energy Board (OEB) for regulated prices, the impact of regulatory decisions by the OEB and other regulatory bodies, 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 similar measures presented by 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 18,096 megawatts (MW) as at December 31, 2025.

As at December 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 owned and operated through the Company's subsidiary operating as Atura Power. Through the Company's subsidiary, DNNP LP, OPG is also constructing the first grid-scale small modular reactor (SMR) at the Darlington New Nuclear Project (DNNP) site in Ontario, Canada. In December 2025, DNNP LP entered into a lease arrangement with Ontario Power Generation Inc. with respect to the DNNP site and reimbursed it for capital expenditures on the DNNP incurred to date.

As at December 31, 2025, through a US-based subsidiary, OPG wholly or jointly owned and operated, and held minority interests in, hydroelectric and solar electricity generation and development assets in the United States (Eagle Creek). In October 2025, OPG entered into an agreement to sell Eagle Creek. The transaction closed on January 9, 2026, resulting in the Company no longer having electricity generation operations or facilities in the United States. The Eagle Creek portfolio had an in-service generating capacity of 701 MW as at December 31, 2025. Further details on the transaction can be found in the section, *Significant Developments* under the heading, *Sale of US Electricity Generation Operations*.

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.

In addition, as at December 31, 2025, OPG owned two nuclear generating stations in Ontario, Canada, 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). These leased stations are not included in the Company's electricity generation and other operating statistics set out in this MD&A.

Corporate Vision and Strategy

OPG's vision is to electrify life in one generation, with a mission to build a sustainable future powered by the Company's electricity, ideas and people.

OPG's corporate strategy sets out the Company's direction for the future, guiding how it will help meet the province's rising demand for electricity, while delivering value to the Shareholder and supporting growth, reliability and energy security for Ontario. The strategy supports Ontario's Integrated Energy Plan and establishes the following long-term areas of focus for OPG: build new energy infrastructure, modernize its business and deliver customer value, and enable electrification and demand growth. Additional information about OPG's Corporate Strategy can be found in the section, *Description of the Business* under the heading, *Corporate Strategy* in the Company's 2025 AIF. Additional information regarding Ontario's Integrated Energy Plan can be found in the section, *Significant Developments* under the heading, *Ontario's Integrated Energy Plan*.

Reporting Structure and Business Segments

The composition of OPG's reportable business segments effective as at December 31, 2025 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) and are prescribed as regulated facilities by the OEB by *Ontario Regulation 53/05* under the *Ontario Energy Board Act, 1998* (*Ontario Regulation 53/05*). The operating results related to these facilities are described in the Regulated – Hydroelectric Generation and Regulated – Nuclear Generation business segments, respectively. *Ontario Regulation 53/05* also prescribes any SMRs located on the DNNP as regulated facilities by the OEB, with the associated project expenditures and operating results of DNNP LP included in the Regulated – Nuclear Generation business segment. The Regulated – Nuclear Generation business segment also includes revenue from the lease of the generating stations to Bruce Power.

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 waste (known 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. As at December 31, 2025, through Eagle Creek, the business segment also included 85 wholly or jointly owned and operated hydroelectric generating stations and one solar facility 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 a battery energy storage system at the Napanee GS site (Napanee BESS), an expansion of the combined cycle plant at the Napanee GS (Napanee Combined Cycle GS Expansion Project), and the Niagara Hydrogen Centre (NHC), all of which are under construction.

A detailed description of OPG's business segments is provided in the section, *Discussion of Operating Results by Business Segment*.

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. The Pickering GS is expected to be taken offline in September 2026 in preparation for the refurbishment of the station's Units 5 to 8. Units 1 to 4 of the Pickering GS have been permanently shut down and have been or are being placed in a safe storage state. Further details on OPG's plan for continued operation of Units 5 to 8 of the Pickering GS can be found in the section, *Significant Developments* under the heading, *Pickering Refurbishment* and *Core Business and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability*.

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 December 31 was as follows:

(MW)	**2025**	**2024**
Regulated – Nuclear Generation [1]	**4,698**	4,698
Regulated – Hydroelectric Generation [2]	**6,572**	6,566
Contracted Hydroelectric and Other Generation [2, 3]	**4,083**	4,080
Atura Power	**2,743**	2,715
Total [4]	**18,096**	18,059

[1] The in-service generating capacity as at December 31, 2025 and December 31, 2024 excluded 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 December 31, 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 generating 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 held through Eagle Creek. As at December 31, 2025, Eagle Creek's in-service generating capacity included 698 MW from hydroelectric generating stations and 3 MW from an owned and operated solar facility placed in service in December 2025. Effective January 9, 2026, OPG completed the sale of Eagle Creek.

[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 generating stations are excluded from electricity generation and operating statistics set out in this MD&A.

The total in-service generating capacity as at December 31, 2025 increased by 37 MW compared to December 31, 2024. The increase was primarily 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.

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 OEB is an independent, quasi-judicial tribunal that reports to the Legislate of the Province through the Ontario Ministry of Energy and Mines and regulated market participants in Ontario's electricity and natural gas industries. The OEB's mandate and authority come from the *Ontario Energy Board Act, 1998*, the *Electricity Act, 1998* and other provincial statutes.

OPG's regulated prices are generally designed to permit the recovery, over a forecasted generation volume, of an allowed level of operating costs and capital investment and to earn a prescribed rate of return on the deemed equity portion (ROE) of the capital invested in the regulated assets, known as rate base. Rate base for OPG's regulated facilities represents the average net level of investment in the associated fixed and intangible assets in service and an allowance for working capital. *Ontario Regulation 53/05* 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.

In December 2025, the Province amended *Ontario Regulation 53/05* to prescribe DNNP LP as a new OEB rate regulated electricity generator, subject to the OEB's satisfaction that DNNP LP has met certain conditions, and to set out certain additional requirements the OEB must follow in setting regulated prices for the DNNP SMR facilities and OPG's existing nuclear facilities. Among these new requirements, *Ontario Regulation 53/05* established a mechanism for OPG's regulated prices to recover interest amounts in respect of the capital expenditures on the Pickering Refurbishment project and the capital expenditures on the DNNP prior to such assets being placed in service, effective January 1, 2026. Ontario Power Generation Inc. and DNNP LP are Ontario's only electricity generators subject to rate regulation by the OEB. Further details regarding the December 2025 amendments to *Ontario Regulation 53/05* can be found in the section, *Significant Developments* under the heading, *Regulation Enabling Interest Cost Recovery During Construction of OPG's Major Nuclear Projects* and in the section, *Core Business and Outlook* under the heading, *Financial Strength – Achieving Appropriate Return*.

The following table presents the OEB-authorized regulated prices for electricity generated from the 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 for the 2022-2026 period were established using a rate smoothing approach that deferred, in certain years, 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), while 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 was set equal to the 2021 hydroelectric base regulated price pursuant to *Ontario Regulation 53/05*. The regulated prices set for the 2022-2026 period have supported 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 OPG's regulated hydroelectric facilities. The OEB's decisions on the application also supported the advancement of SMRs at the DNNP site.

Since 2017, the base regulated prices for OPG's nuclear electricity generation (nuclear base regulated price) have been set under a custom incentive regulation framework, based on an OEB-approved nuclear revenue requirement and production forecast for each year. The OEB-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. In accordance with *Ontario Regulation 53/05*, OPG's 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 resulting revenues reduce the nuclear revenue requirement and OPG's resulting costs increase it. Consistent with the requirements of *Ontario Regulation 53/05* applicable to the Darlington Refurbishment project period, in setting the nuclear base regulated prices effective January 1, 2022, the OEB deferred, in certain years of the 2022-2026 period, a portion of the approved annual nuclear revenue requirements for future collection in the Rate Smoothing Deferral Account.

Prior to being set equal to the 2021 hydroelectric base regulated price pursuant to *Ontario Regulation 53/05* effective January 1, 2022, the hydroelectric base regulated prices since 2017 were determined using an incentive ratemaking methodology, by annually escalating the hydroelectric base regulated prices that had been previously established using a forecast cost-of-service approach, with some adjustments, using an OEB-approved formula equal to an inflation factor based on indices published annually by the OEB, less a stretch factor adjustment.

Further details regarding the regulated prices in effect as of January 1, 2022 can be found in the section *Core Business and Outlook* under the heading, *Financial Strength – Achieving Appropriate Return*.

In December 2025, OPG filed a five-year application with the OEB for new regulated prices for electricity generated from OPG's regulated hydroelectric and nuclear facilities, including for the DNNP SMR facilities on behalf of DNNP LP, with a proposed effective date of January 1, 2027. The application reflects the December 2025 amendments to *Ontario Regulation 53/05*. For the nuclear facilities, the application proposes base regulated prices determined under a custom incentive regulation framework consistent with prior OPG applications for regulated prices, based on a revenue requirement and production forecast for each of the five years. As required by *Ontario Regulation 53/05* with respect to any period until the effective date of the OEB's first order setting regulated prices for the DNNP SMR facilities after the DNNP has been completed, the application requests blended nuclear base regulated prices for OPG's existing nuclear facilities and the DNNP SMR facilities, by combining the respective annual revenue requirements and production forecasts. For the regulated hydroelectric facilities, the application proposes base regulated prices determined under a custom incentive regulation framework that would rebase the base regulated price using a forecast cost-of-service approach for the 2027 year, based on the corresponding revenue requirement and production forecast, and, for the four subsequent years, escalate the price annually using a formula that includes an inflation factor based on indices published annually by the OEB, as increased by an incremental capital funding adjustment to support forecasted investment levels and as reduced by a stretch factor adjustment. The proposed regulated prices would enable OPG's investments in its nuclear and hydroelectric assets that will help meet Ontario's growing electricity demand in alignment with Ontario's Integrated Energy Plan. The OEB has processed OPG's application and the public proceeding is underway.

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, including those in respect of DNNP LP, are established pursuant to *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 6 of OPG's 2025 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, for disposition of regulatory account balances as at December 31, 2019, less amounts previously approved for recovery of repayment of any such balances through existing rate riders. In June 2024, the OEB issued a decision and order approving a proposed complete settlement on OPG's 2023 application requesting the disposition of regulatory account balances as at December 31, 2022, less amounts previously approved for recovery or repayment of any such balances through existing rate riders, and establishing incremental rate riders on nuclear and regulated hydroelectric electricity generation for such disposition.

OPG's December 2025 application for new regulated prices with the OEB requests new rate riders, effective January 1, 2027, to recover or repay the December 31, 2024 balances in most of the Company's regulatory accounts, including the Rate Smoothing Deferral Account, less amounts previously approved for recovery or repayment of any such balances through existing rate riders in effect to December 31, 2026. The application also requests continuation of most existing deferral and variance accounts and proposes certain new deferral and variance accounts, including in respect of DNNP LP.

Non-Regulated Generation

All of OPG's non-regulated generating assets in Ontario are subject to ESAs with the IESO. As of December 31, 2025, the contracts for Ontario-based generating assets had the following expiration dates:

Generating Facility	Generation Type	Term	Contract Expiry Date
Contracted Hydroelectric and Other Generation			
Atikokan GS	Biomass	5 years	July 2029
Lennox GS [1]	Oil or Natural Gas	7 + 5 years	April 2034
Nanticoke solar facility	Solar	20 years	March 2039
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 [2]	Hydroelectric	50 years	January 2064
Peter Sutherland Sr. GS	Hydroelectric	50 years	March 2067
Atura Power			
Portlands Energy Centre [3]	Natural Gas	20 years	April 2029
Brighton Beach GS	Natural Gas	10 years	July 2034
Halton Hills GS	Natural Gas	25 years	April 2035
Napanee GS	Natural Gas	20 years	March 2040

[1] In May 2025, OPG secured a new five-year agreement for the facility. The existing ESA will remain in place until April 2029, at which time the new ESA expiring in April 2034 will take effect.
[2] These facilities are also known as the Lower Mattagami generating stations.
[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.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's operating results for the years ended December 31, 2025 and December 31, 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)	**2025**	**2024**
Revenue	**8,355**	7,187
Fuel expense	**1,421**	1,049
Operations, maintenance and administration expenses	**2,816**	3,318
Depreciation and amortization expenses	**1,413**	1,270
Accretion on fixed asset removal and nuclear waste management liabilities	**1,243**	1,221
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(1,138)**	(1,102)
Other net expenses	**425**	69
Earnings before interest and income taxes	**2,175**	1,362
Net interest expense	**194**	186
Income tax expense	**453**	170
Net income	**1,528**	1,006
Net income attributable to the Shareholder	**1,509**	988
Net income attributable to non-controlling interest [1]	**19**	18
Electricity generation (TWh) [2]	**88.3**	82.1
Cash flow provided by operating activities	**3,708**	2,211
Capital expenditures [3]	**5,860**	3,725
Earnings (loss) before interest and income taxes by segment		
Regulated – Nuclear Generation	**1,399**	342
Regulated – Hydroelectric Generation	**574**	581
Contracted Hydroelectric and Other Generation	**(110)**	242
Atura Power	**270**	276
Total electricity generating business segments	**2,133**	1,441
Regulated – Nuclear Sustainability Services	**(94)**	(108)
Other	**136**	29
Earnings before interest and income taxes	**2,175**	1,362

[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.

Net income attributable to the Shareholder was $1,509 million for 2025, representing an increase of $521 million compared to 2024. Earnings before interest and income taxes (EBIT) were $2,175 million for 2025, representing an increase of $813 million compared to 2024.

Significant factors that increased EBIT:

- Lower OM&A expenses of $507 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 $500 million from the Regulated – Nuclear Generation business segment due to higher electricity generation of 5.0 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.

Significant factor that decreased EBIT:

- Higher other net expenses of $356 million from the Contracted Hydroelectric and Other Generation business segment, primarily due to a non-recurring pre-tax loss of $477 million recognized in the fourth quarter of 2025 related to the sale of Eagle Creek , partially offset by a gain of $83 million recorded in the fourth quarter of 2025 within the Other category related to changes in the fair market value of non-core equity holdings in a private nuclear technology company. Further details on the Eagle Creek transaction can be found in the section, *Significant Developments* under the heading, *Sale of US Electricity Generation Operations*.

Net interest expense increased by $8 million in 2025, compared to 2024, 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, largely 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 $283 million in 2025, compared to 2024. The increase was mainly due to the impact of higher earnings before income taxes.

Electricity Generation

Electricity generation for the years ended December 31 was as follows:

(TWh)	**2025**	**2024**
Regulated – Nuclear Generation	**38.0**	33.0
Regulated – Hydroelectric Generation	**30.9**	32.5
Contracted Hydroelectric and Other Generation [1]	**5.6**	5.0
Atura Power	**13.8**	11.6
Total OPG electricity generation	**88.3**	82.1

[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 6.2 TWh in 2025, compared to 2024.

Year-over-year changes in electricity generation:

- Higher electricity generation of 5.0 TWh from the Regulated – Nuclear Generation business segment, 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 increase was 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;
- Lower electricity generation of 1.6 TWh from the Regulated – Hydroelectric Generation business segment, primarily due to lower water inflow conditions across most of Ontario during the second half of 2025;
- Higher electricity generation of 0.6 TWh from the Contracted Hydroelectric and Other Generation business segment, primarily due to higher water flows across the contracted hydroelectric facilities in northeastern Ontario during the second and third quarters of 2025; and
- Higher electricity generation of 2.2 TWh 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 145.6 TWh in 2025, compared to 140.4 TWh 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 2025, compared to 2024. Production forgone at OPG's regulated hydroelectric stations due to SBG conditions was 0.7 TWh in 2025 and 0.4 TWh 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 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 2025 was $3,708 million, compared to $2,211 million for 2024. The increase 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 years ended December 31 were as follows:

(millions of dollars)	**2025**	**2024**
Regulated – Nuclear Generation – Darlington Refurbishment Project	**711**	988
Regulated – Nuclear Generation – Pickering Refurbishment	**1,523**	372
Regulated – Nuclear Generation – DNNP	**978**	571
Regulated – Nuclear Generation – Excluding Darlington Refurbishment, Pickering Refurbishment and DNNP	**569**	604
Regulated – Hydroelectric Generation	**755**	434
Contracted Hydroelectric and Other Generation	**150**	220
Atura Power	**850**	382
Other	**324**	154
Total capital expenditures [1]	**5,860**	3,725

[1] Includes net changes in accruals.

Total capital expenditures were $5,860 million in 2025, representing an increase of $2,135 million, compared to 2024.

Year-over-year changes in capital expenditures:

- Decrease of $277 million for the Darlington Refurbishment project, 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;
- Increase of $1,151 million for the Pickering Refurbishment project 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;
- Increase of $407 million for the DNNP due to the commencement of construction activities for the first SMR, Unit 1, and infrastructure that would be common for all four planned SMRs at the DNNP site in 2025;
- Decrease of $35 million related to other projects for the Regulated – Nuclear Generation business segment. The decrease was primarily due to the completion of the water treatment facility and the replacement of primary moisture separators at the Darlington GS in 2024, largely offset by capital expenditures on other sustaining projects in 2025. 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*;
- Increase of $321 million for the Regulated – Hydroelectric Generation business segment, primarily due to higher expenditures on the redevelopment of the Kakabeka Falls and other hydroelectric generating stations as well as the ongoing refurbishment program across the regulated hydroelectric fleet;
- Decrease of $70 million for the Contracted Hydroelectric and Other Generation business segment, primarily due to lower expenditures on the Smoky Falls Dam Safety project and the Little Long Dam Safety project;
- Increase of $468 million for the Atura Power business segment, primarily due to higher expenditures on the development of the Napanee BESS, Napanee Combined Cycle GS Expansion Project and the NHC, as well as higher expenditures at existing combined cycle plant facilities; and
- Increase of $170 million for the Other category, 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.

Capital Placed in Service

During 2025, the Company placed $1,478 million of capital in service, compared to $3,237 million in 2024. The decrease was primarily due to capital placed in service in 2024 related to the return to service of Unit 1 of the Darlington GS following refurbishment in November 2024. Further details on the Company's major projects can be found in the sections, *Core Business and Outlook* under the heading, *Project Excellence,* and *Significant Developments.*

SIGNIFICANT DEVELOPMENTS

Darlington Refurbishment

On March 7, 2026, Unit 4 of the Darlington GS was synchronized to the electricity grid, with high power operation achieved during final commissioning, and is now in the final stages of a full and safe return to service in March 2026, over four months ahead of the original schedule. The return to service of Unit 4 will mark the substantial completion of the four-unit Darlington Refurbishment project, which will continue to provide at least another 30 years of approximately 3,500 MW of cost effective, reliable and clean baseload electricity generating capacity for Ontario. The total project completion costs for the four units, including the impacts of the COVID-19 pandemic, are expected to be approximately $150 million below the $12.8 billion budget, upon completion of project closure activities.

The Darlington Refurbishment project is discussed further in the section, *Core Business and Outlook* under the heading, *Project Excellence*.

Pickering Refurbishment

On November 26, 2025, the Province announced its approval of OPG's plan to proceed with the refurbishment of Units 5 to 8 of the Pickering GS. The total budget for refurbishing the four units, including interest, cost escalation, and contingency, is $26.8 billion, which represents the release-quality estimate approved by the OPG Board of Directors (Board). The project will incorporate the benefits of experience gained through the completed refurbishment of the four units at the Darlington GS. As planned, OPG expects to remove Units 5 to 8 of the Pickering GS from service in September 2026, followed by the defueling of the reactors, with the execution phase of the project commencing in January 2027. The first unit scheduled to complete refurbishment, Unit 5, is expected to return to service in 2031, with the overall refurbishment anticipated to be completed by 2034. The Province had previously announced its approval for OPG to proceed with the definition phase of the refurbishment in January 2025. Once refurbished, the Pickering GS will continue to provide over 2,000 MW of baseload generating capacity, helping to meet Ontario's demand for electricity for over 30 years.

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 New Nuclear Project

Through its DNNP LP subsidiary, OPG continues to advance the DNNP and plans 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.

In April 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 approval of OPG's plan to proceed with the execution phase of the first SMR at the DNNP site (Unit 1). Unit 1 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. This total budget of $7.7 billion represents the release-quality estimate for Unit 1 and such shared infrastructure, inclusive of interest, cost escalation and contingency, and was approved by the Board. The total cost of the four-unit DNNP, including interest, cost escalation and contingency, has been currently estimated at approximately $20.9 billion. OPG and its project partners will continue to refine the total estimated project cost during the definition phase of the three additional units, incorporating lessons learned from the construction of Unit 1 and the Darlington Refurbishment project.

As supported by the Province, OPG continues to advance planning and licensing activities for the three additional SMRs at the DNNP site. In March 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 the three additional units, the DNNP's total generating capacity is expected to reach approximately 1,200 MW.

Initial Project Description for Potential New Nuclear Generation at OPG's Wesleyville Site

In December 2025, OPG submitted the *New Nuclear at Wesleyville in Port Hope* Initial Project Description (IPD) to the Impact Assessment Agency of Canada. The IPD is a preliminary document that provides an overview of the proposed project in Port Hope, where OPG is exploring the potential for new nuclear energy generation at its Wesleyville site. As requested by the Province, OPG has been working with local communities, First Nations, stakeholders and the public to determine their support for such a project. OPG developed the IPD based on a range of potential nuclear technologies that could be deployed at the site, which is already zoned for electricity generation and is proximate to transmission infrastructure, with generating capacity of up to 10,000 MW.

The IPD submission begins a multi-year federal Impact Assessment process to assess the impact of a project and to apply to the CNSC for a Licence to Prepare Site. The Impact Assessment will include an assessment of potential impacts on the environment, health, social and economic conditions, and Indigenous rights, and explore how adverse effects could be mitigated. Participation of Indigenous and local communities is essential to this process. In recognition of this, OPG has received substantial input from the Alderville, Curve Lake, Hiawatha, and Mississaugas of Scugog Island First Nations of the Williams Treaties First Nations in preparing the IPD.

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, which, if approved, would have a combined generating capacity of up to 430 MW. This includes the proposed Nine Mile Rapids generating station on the Abitibi River and the proposed Grand Rapids 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 are jointly leading a co-planning process to determine a potential path forward for the development of these sites, contingent on community support. To support the co-planning process and the Indigenous communities' ratification vote for these proposed projects, OPG has undertaken a series of early-stage studies at the Abitibi and Mattagami Rivers and engaged an Owner's Engineer to develop conceptual design options. The Indigenous communities' ratification vote is planned for the fourth quarter of 2026.

Ontario's Integrated Energy Plan

In June 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 significantly leading up to 2050, driven by anticipated population growth, industrial expansion, and greater electrification across the province. 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.

OPG's major approved and proposed investments to develop new or refurbish existing generating assets are in alignment with the Province's integrated energy plan. This includes the Pickering Refurbishment project, the DNNP, the refurbishment and redevelopment of hydroelectric assets, and the potential for new generation at the Company's existing sites in southern Ontario, including new nuclear energy generation at the Wesleyville site, and for new hydroelectric generation in northern Ontario, including the proposed Nine Mile Rapids and Grand Rapids generating stations.

World Association of Nuclear Operators Recognition

In 2025, OPG hosted World Association of Nuclear Operators (WANO) peer reviews at both the Darlington GS and Pickering GS. The reviews focused on the progress made in safety, equipment reliability, performance and continuous improvement at the stations since the last review. Through these visits, the Darlington GS and the Pickering GS were recognized as performing at the highest levels of operational safety and reliability.

Collective Agreement with Society of United Professionals

The governing two-year collective agreement between the Society of United Professionals (Society) and OPG expired on December 31, 2025. On January 26, 2026, the Society and OPG received the final arbitration award for a three-year collective agreement, covering the period from January 1, 2026 to December 31, 2028.

Equity Injection from Province

In December 2025, the Province committed to providing $5 billion in equity injections to OPG over the 2025-2027 period. As part of this arrangement, in December 2025, OPG issued its first 1,000,000 non-voting Class B preferred shares to the Province at $1,000 per share, generating $1 billion in proceeds.

Green Bonds

In March 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 OPG's Sustainable Finance Framework.

Equity Commitment Agreements for Darlington New Nuclear Project

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 provincial Building Ontario Fund (BOF) and up to $2 billion through the federal Canada Growth Fund (CGF), subject to the satisfaction of certain conditions. OPG will remain the majority owner, project manager 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, in DNNP LP. The CGF and BOF's capital will be made available to OPG as required by the project, in two tranches – capital funding for Unit 1 and additional capital for the construction of three additional SMRs once the project meets certain milestones. The initial equity investment from CGF and BOF to DNNP LP is expected to be completed by the second quarter of 2026.

Regulation Enabling Interest Cost Recovery During Construction of OPG's Major Nuclear Projects

In December 2025, the Province amended *Ontario Regulation 53/05* to establish a mechanism for recovery through regulated prices of interest amounts in respect of the capital expenditures on the Pickering Refurbishment project and the capital expenditures on the DNNP prior to such assets being placed in service, effective January 1, 2026. Under the mechanism, the OEB-approved revenue requirement used to set regulated prices for OPG's existing nuclear facilities and the DNNP SMR facilities must include an amount equal to the product of the forecast cumulative capital expenditures to be incurred in respect of the Pickering Refurbishment project and the DNNP, respectively, other than any such amounts that have been placed in service, and OPG's cost of long-term borrowing approved by the OEB. Effective January 1, 2026, the amendments also established variance accounts for OPG to record, as applicable and including in respect of DNNP LP, the differences between such forecast interest amounts included in the respective revenue requirements and the amounts determined by multiplying such actual cumulative capital expenditures by OPG's cost of long-term borrowing approved by the OEB. The regulation requires the OEB to authorize disposition of the balances in these accounts, together with interest at OPG's cost of long-term borrowing approved by the OEB, on an annual basis in the year following the year in which the amounts are recorded in the account.

As a result of providing for recovery of interest amounts concurrent with the associated capital expenditures, in addition to helping support the Company's financing requirements, the above mechanism will reduce the corresponding rate base values for the Pickering Refurbishment project and the DNNP, all of which is expected to ultimately lower the total amounts recoverable from customers over the life of these assets. OPG's December 2025 application for new regulated prices with the OEB reflects the requirements of the above mechanism and seeks recovery of the respective forecast interest amounts for each of the five years covered by the application. For the 2026 year, such interest amounts will be recorded in the respective variance accounts, for recovery during the 2027 year pursuant to the regulation. For all other capital assets, OPG's December 2025 application seeks to maintain the historical practice of recovering capitalized interest costs through the return of and on the associated rate base upon the assets being placed in service.

Sale of US Electricity Generation Operations

In October 2025, OPG entered into an agreement to sell Eagle Creek. On January 9, 2026, OPG completed the sale of Eagle Creek for consideration of USD $1.48 billion (C$2.05 billion) inclusive of debt to be assumed by the buyer and other closing adjustments.

As a result of the execution of the purchase and sale agreement, Eagle Creek met the requirements to be presented as held for sale in accordance with US GAAP in the fourth quarter of 2025. Accordingly, a pre-tax loss of $477 million was recognized during the fourth quarter of 2025.

Federal Clean Electricity Investment Tax Credits

In November 2025, the Government of Canada reintroduced draft legislation to implement the Clean Electricity Investment Tax Credit (CEITC), which would be available to both federally taxable entities and federal tax-exempt entities including OPG. In February 2026, the draft legislation passed the House of Commons of the Parliament of Canada, requiring approval from the Senate of the Parliament of Canada before achieving Royal Assent.

For eligible projects commencing after March 2023, the CEITC would provide a 15 percent refundable tax credit on eligible clean electricity investments made after April 16, 2024. If certain labour conditions are not met, these refundable credits would be reduced to five percent. The CEITC would be available for certain clean energy projects for the period up to and including 2034. If the draft legislation is enacted as proposed, 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 would qualify for the CEITC. OPG's December 2025 application for new regulated prices with the OEB proposes regulatory account mechanisms to record the revenue requirement impact of the CEITCs for OPG's regulated facilities for repayment to customers, if the legislation is enacted, which would lower the total amounts ultimately recoverable from customers.

CORE BUSINESS AND OUTLOOK

OPG maintains four business imperatives that represent the areas in which OPG aims to demonstrate excellence in order to enable its corporate strategy. These business imperatives are operational excellence, project excellence, financial strength and social licence.



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 future ready workforce. As part of its commitment to operational excellence, OPG continues to optimize the business through an ongoing focus on strong execution, a continuous improvement culture and advancing innovation. 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 2025 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 maximizing electricity generation output from these nuclear generating stations by continuing to invest in projects and upgrades to improve plant reliability, maintaining existing assets 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. Based on such most recent assessment, conducted for the 2024 year, the 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 Power Workers' Union (PWU) and the 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. Effective November 1, 2025, OPG has implemented these provisions in accordance with the CNSC's direction.

Pickering GS

OPG's plan to maximize the safe and reliable operating life of the Pickering GS includes operating Units 5 to 8 until the end of September 2026, prior to taking these units offline for refurbishment. In 2024, the CNSC amended the existing power reactor operating licence for the Pickering GS, authorizing the operation of Units 5 to 8 until the end of 2026. This licence is valid until August 31, 2028. In June 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 the planned refurbishment activities for Units 5 to 8. The two-part public hearing on the application is scheduled to be held by the CNSC in June 2026 and October 2026.

With the Province's approval announced in January 2025, the Pickering Refurbishment project has been advancing through the definition phase. During the fourth quarter of 2025, OPG completed the development of the release-quality estimate and schedule for the project, and associated project execution plan and project scope optimization. The project continues to progress prerequisite facilities and infrastructure scope, detailed engineering, and procurement and contracting work. The definition phase is expected to last through 2026. With the Province's approval announced in November 2025, the execution phase of the project is expected to commence in January 2027. Further details on the Pickering Refurbishment project can be found in the section, *Significant Developments* under the heading, *Pickering Refurbishment*.

The approved base nuclear 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. Following its announcement of support in 2022 for the continued safe operation of these units until the end of September 2026, the Province 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. Subsequently, effective July 1, 2025, the Province amended *Ontario Regulation 53/05* to clarify the scope of the 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. 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. The disposition of the account balance will be subject to the OEB's review in a future proceeding.

As planned, Unit 1 and Unit 4 of the Pickering GS ceased commercial operation and were permanently taken offline in the fourth quarter of 2024, after over 50 years of service. Following the end of commercial operation, both units 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 shut down units from the operating units. These activities must be conducted while meeting nuclear, radiological, industrial safety, and environmental protection standards. The defueling of Unit 1 and Unit 4 was completed safely in February 2025 and June 2025, respectively, and the de-watering of Unit 1 and Unit 4 was completed safely in March 2025 and December 2025, respectively. Work is progressing on isolating the units and placing various sub-systems in a safe state. 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 the units in a safe storage state are charged against the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities) and reimbursed from the Nuclear Segregated Funds.

Darlington GS

OPG continues to make investments in the Darlington GS in order to ensure its ongoing safe and reliable post-refurbishment operations, maintain existing assets and position the station for industry-leading operating and cost performance in the longer term. This includes investments in life cycle and aging management projects, facility upgrades, and required investments in support of regulatory commitments. OPG continued to progress a number of such projects at the Darlington GS during 2025, including the main power output protection system replacement, revenue metering transformer replacement and main power output transformer fire containment system upgrade to meet compliance commitments and ensure continued reliable operation.

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), 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. Following the replacement of the primary moisture separators in the first two SGs in Unit 3, completed in 2023, and in the four SGs in Unit 1 and Unit 4, completed in 2024, 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. The project is progressing with ongoing execution planning activities.

In September 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.

Renewable Generation Operations

The objectives of OPG's hydroelectric operations include operating and maintaining the generating facilities in a safe, reliable, efficient and cost-effective manner, while addressing aging conditions and 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.

Given the very long-term nature of the Company's hydroelectric fleet, OPG's plans to address asset aging conditions and maximize the fleet's value are often accomplished through multi-year capital investment and other programs, including replacements and upgrades of turbine runners, refurbishment or replacement of existing generators, transformers and control systems, and redevelopment of the facilities. OPG also pursues opportunities to expand generating capacity at 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 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 turbine-generator refurbishment program for its hydroelectric generating units across Ontario. During 2025, activities related to this program included the following:

- Initiated the execution of refurbishment for Unit 19 and Unit 20 at the Sir Adam Beck II GS and Unit 6 and Unit 8 at the Sir Adam Beck I GS, located in Niagara Falls, Ontario. OPG is also continuing the execution of the refurbishment of Unit 4 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, 2025, life-to-date capital expenditures for the refurbishment of both Sir Adam Beck I and II generating stations were $92 million;
- Completed the refurbishment of Unit 9 and continued execution of the refurbishment of Unit 12 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. As of December 31, 2025, life-to-date capital expenditures for the refurbishment of the R.H. Saunders GS were $76 million;
- 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. As of December 31, 2025, life-to-date capital expenditures for the station's refurbishment were $47 million; and
- Completed the refurbishment of Unit 2 and continued execution of the refurbishment of Unit 1 at the Otter Rapids GS, located on located on the Abitibi River in northeastern Ontario. As of December 31, 2025, life-to-date capital expenditures for the station's refurbishment were $101 million.

In December 2025, the Frederick House Lake Dam, located in northeastern Ontario, was returned to service ahead of schedule and under its approved budget. Project closure activities are expected to be completed during 2026. The dam was built in the 1930s and provides water storage to the Abitibi Canyon GS. The project rehabilitated the structures in alignment with provincial dam safety requirements.

Construction activities continue to progress on the rehabilitation of the concrete infrastructure at the R.H. Saunders GS, Abitibi Canyon Dam and other hydroelectric facilities across Ontario.

OPG coordinates and collaborates with various government agencies, municipalities, Indigenous Nations and communities and community stakeholders to ensure the river systems on which the Company operates are managed safely and effectively, while meeting electricity generation needs. Ontario's watersheds experienced a relatively wet spring in 2025, followed by an extremely dry fall season across the province. OPG managed these conditions safely and effectively by maintaining a strong focus on dam and public safety and coordinating with municipalities, Indigenous communities and community stakeholders in the affected watersheds during both high and low water flow conditions.

Thermal Operations

OPG's thermal generation fleet comprises the Lennox oil/gas dual-fueled generating station, the Atikokan 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.

In May 2025, OPG secured a new five-year ESA for the Lennox GS under the IESO's Medium-Term 2 (MT2) Request for Proposal process. Together with its existing ESA, this will support ongoing operation of the Lennox GS until 2034, enabling it to continue providing 2,100 MW of electricity generating capacity to Ontario's electricity system. The existing ESA will remain in place until April 2029, at which time the new ESA will take effect.

In 2023, the IESO awarded 42.5 MW and 50.0 MW in average generating capacity upgrades to the Brighton Beach GS and Portlands Energy Centre, respectively. In January 2026, this contractual capacity upgrade at the Brighton Beach GS was placed in service. The capacity upgrade at the Portlands Energy Centre is expected to be in service in 2026.

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 pursues 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. 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 major projects and growth strategies and managing risks. This includes preparing for a period of parallel execution of the Pickering Refurbishment project and the DNNP, during which the Company's operating cost structures will support activities at the Pickering GS to preserve readiness to return Units 5 to 8 to service and to maintain the site during the four-unit refurbishment outage, and to ensure readiness to operate DNNP's Unit 1 upon its completion. Accomplishing these objectives is anchored in leveraging a highly skilled, high-performing and diverse workforce, and continuous investment in technology and innovation.

OPG is continuing to advance an enterprise-wide strategy to align the Company's digital infrastructure with its strategic objectives, drive value from investments in technology and address areas of risk. 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 include enabling an adaptive technology ecosystem, supporting operational and project requirements, enhancing process effectiveness, and strengthening cybersecurity.



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, striving for excellence in the planning and delivery of all capital and maintenance projects across the organization.

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 across the enterprise is facilitated by a centralized enterprise projects organization and involves, among others: leveraging a common, scalable project delivery model based on industry best practices, optimizing contracting strategies, and engaging qualified and experienced engineering, procurement and construction vendors.

Generation Development Projects in Execution Phase

OPG's major projects in the execution phase as at December 31, 2025 are outlined below.

Project *(millions of dollars)*	**Life-to-Date Expenditures** [1]	**Approved Budget** [1]	**Expected In-service Date**
Darlington Refurbishment Project	12,177	12,800 [2]	2026 – Unit 4
Darlington New Nuclear Project	1,885	7,700 [3]	2030 – Unit 1
Redevelopment of Kakabeka Falls Hydroelectric GS	188	519	2028
Atura Power Development Projects	937	1,500 [4]	2026 – Napanee BESS and Niagara Hydrogen Centre [5] 2028 – Napanee Combined Cycle GS Expansion Project

[1] Represents capital expenditures and, where approved in the budget, associated project OM&A expenses.
[2] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.
[3] The approved budget of $7.7 billion includes $6.1 million allocated to Unit 1 and $1.6 billion allocated for systems and services that would be common to all four SMRs planned as part of the project. Project cost performance will be measured inclusive of interest amounts recoverable through regulated prices concurrent with the associated capital expenditures.
[4] The total project budget of approximately $1.5 billion is for the Napanee BESS, the Niagara Hydrogen Centre and the Napanee Combined Cycle GS Expansion projects.
[5] The expected in-service date of the Niagara Hydrogen Centre was previously updated from 2025 to 2026.

Darlington Refurbishment

The Darlington Refurbishment project execution 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 Darlington Refurbishment project is a multi-phase program comprising five major sub-projects. 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.

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 and the refurbishment of the third unit, Unit 1, was completed in November 2024, both ahead of their original schedule. The refurbishment of the last unit, Unit 4, commenced in July 2023, after Unit 3 was returned to service and is currently in the fourth and final major segment, Power Up. On March 7, 2026, Unit 4 was synchronized to the electricity grid, with higher power operation achieved during final commissioning, and is now in the final stages of a full and safe return to service in March 2026, over four months ahead of its original schedule. The total project completion costs for the four units, including the impacts of the COVID-19 pandemic, are expected to be approximately $150 million below the $12.8 billion budget, upon completion of project closure activities.

Darlington New Nuclear Project

Through its DNNP LP subsidiary, OPG continues to advance the construction of Canada's first grid-scale SMR, at the DNNP site, and plans to connect it to electricity grid by the end of 2030. The DNNP is a multi-phase program organized by major work bundles, with the majority of the execution phase scope for Unit 1 comprising the following:

- Design Engineering, which represents substantially all engineering and design work necessary to deliver the SMR;
- Nuclear Island, which includes the procurement, construction, installation, and testing of components within the nuclear island, comprised of the reactor building, control building, radiation waste building and plant services building;
- Conventional Island, which includes the procurement, construction, installation, and testing of components within the conventional island, defined primarily as the turbine building as well as work associated with the electricity grid connection, transmission tie-ins and security building; and
- Balance of Plant, which involves the procurement, construction, installation, and testing of components across general facilities and site infrastructure, condenser cooling water system and power block and yard construction.

During 2025, the project completed the baseline detailed design milestone as well as the construction of the pre-assembly building, which will support the final assembly of reactor building structural components. The project is progressing towards the construction of the Unit 1 basemat, which represents the foundation of the reactor building. OPG also continues to advance planning and licensing activities for the three additional SMRs, with site grading activities completed in 2025.

Redevelopment of Hydroelectric Generating Stations

OPG is redeveloping several existing hydroelectric generating stations in Ontario that are approaching the end of their operational lives. The redevelopments 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 an additional 80 to 90 years. The facilities currently undergoing redevelopment include the Kakabeka Falls GS, Coniston GS, Stinson GS and Matabitchuan GS, which are all reported in the Regulated – Hydroelectric Generation business segment.

The Kakabeka Falls GS is OPG's second oldest hydroelectric generating station, located along the Kaministiquia River in northwestern Ontario. Its redevelopment project is currently in the execution phase. In 2025, the project completed site demolition work, and the mud slab was poured for the new surge building. The project's expected in-service date is 2028, with an approved budget of $519 million. The project is tracking within the approved budget and schedule. The redeveloped station is expected to have a generating capacity of approximately 27 MW.

OPG initiated the execution phase of a project to redevelop the 114-year-old Matabitchuan GS, located along the Matabitchuan River in northeastern Ontario, in March 2025. During 2025, the construction team mobilized to site, demolished the existing powerhouse superstructure, and began excavation in support of the new powerhouse construction. The project's expected in-service date is in 2028, with an approved budget of $190 million. The project is tracking within the approved budget and schedule. The redeveloped station is expected to have a generating capacity of approximately 12 MW.

The Coniston and Stinson hydroelectric generating stations are located along the Wanapitei River east of Sudbury, Ontario, and are being redeveloped through a single project due to their close proximity and other synergies. During 2025, both powerhouses have been demolished and the primary concrete for the Coniston GS intake structure has been completed. The project's expected in-service date is 2027, with a combined approved budget of $178 million. The project is tracking within the approved budget and schedule. The redeveloped stations are expected to have a combined generating capacity of approximately 12 MW.

Atura Power Development Projects

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. Construction activities were substantially completed in 2025 and the project has advanced into the early stages of commissioning. The project is expected to be completed in 2026 and will operate under a 21-year capacity agreement with the IESO. The project is tracking within the approved budget and schedule.

Atura Power is also 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. The project has substantially completed construction activities and has entered the system integration and commissioning phase during the fourth quarter of 2025. The NHC is expected to be completed in 2026 and is tracking within the approved budget.

Atura Power is also executing a project to add an additional combustion turbine generator unit at the Napanee GS site, which will provide up to 405 MW of generating capacity to Ontario's electricity grid. Engineering and design activities and the procurement of critical equipment were completed during 2025, with permitting activities progressing on schedule. Construction activities commenced during 2025. The project is expected to be completed in 2028 and will operate under a 12-year capacity agreement with the IESO. The project is tracking within the approved budget and schedule.



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, ensures availability of cost-effective funding for operational and project needs, and supports expansion of the business.

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 consumers 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, including major projects, 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 capital structure, and prescribed 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**		**2024**	**2025**	**2026**
Regulated – Nuclear Generation [2]	**8.66%**	**45%**	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 capital structure and prescribed ROE. 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 was reflected in the hydroelectric base regulated prices in effect prior to June 1, 2017 that had been established using a forecast cost-of-service approach. Further information on hydroelectric base regulated prices can be found in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation* under the heading *Regulated Generation*.

OPG continues to invest in the nuclear and hydroelectric rate base, including through the completion of the Darlington Refurbishment project. In establishing the 2022-2026 nuclear base regulated prices, the OEB approved the full amount of the Darlington Refurbishment forecast in-service capital additions to rate base based on the project budget of $12.8 billion, including the then forecasted return to service from the refurbishment of Units 3, 1 and 4.

OPG's December 2025 application for new regulated prices with the OEB seeks approval of forecast in-service capital additions to rate base over the 2027-2031 period in respect of the Pickering Refurbishment project and the DNNP.

As discussed in the section, *Core Business and Outlook* under the headings, *Operational Excellence – Electricity Generation Production and Reliability* and *Project Excellence – Redevelopment of Hydroelectric Generating Stations*, OPG continues to undertake a turbine-generator refurbishment program, redevelopment projects and other capital investments across its regulated hydroelectric facilities to ensure their continued safe and reliable operations. These

renewable assets can have very long service lives and, with maintenance efforts or rebuilding, can continue to supply electricity and be reflected in rate base for the foreseeable future. OPG's December 2025 application for new regulated prices with the OEB seeks approval of an incremental capital funding mechanism to support these investments over the five years covered by the application.

The revenue requirement impact of differences between the OEB-approved forecast capital and non-capital costs incurred by OPG to increase the output of, refurbish or add generating capacity to one or more of its nuclear facilities or regulated hydroelectric facilities, including in respect of the Darlington Refurbishment project and the Pickering Refurbishment project, and such actual costs is recorded in a variance account authorized by the OEB pursuant to *Ontario Regulation 53/05*. The regulation provides for a separate variance account to record the revenue requirement impact of differences between the OEB-approved forecast capital and non-capital costs incurred by OPG for new nuclear generation facilities and such actual costs. The December 2025 amendments to *Ontario Regulation 53/05* established a variance account for DNNP LP to record the revenue requirement impact of differences between the OEB-approved forecast capital and non-capital costs incurred by DNNP LP for the DNNP and such actual costs, as well as differences in net revenue earned by DNNP LP as a result of any difference between the OEB-approved forecast in-service date of a DNNP SMR and such actual date. The disposition of balances recorded in these accounts is subject to the OEB's review.

Consistent with the requirements of *Ontario Regulation 53/05* applicable to the Darlington Refurbishment project period, in setting the nuclear base regulated prices effective January 1, 2022, the OEB deferred, in certain years of the 2022-2026 period, a portion of the approved annual nuclear revenue requirements for future collection in the Rate Smoothing Deferral Account. Pursuant to the OEB's January 2022 payment amounts order, no portion of the approved nuclear revenue requirement was deferred in 2024 or 2025 and none is to be deferred in 2026. 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 related. *Ontario Regulation 53/05* requires the OEB to authorize the recovery of the deferred amounts, together with interest at OPG's cost of long-term borrowing approved by the OEB, on a straight-line basis over a period not to exceed ten years following the end of the Darlington Refurbishment project. OPG's December 2025 application for new regulated prices with the OEB seeks recovery of the balance in the Rate Smoothing Deferral Account over a period of ten years ending December 31, 2036.

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. As part of its decision issued in March 2025, the OEB updated the cost of capital parameters including the prescribed ROE applicable to all electricity transmitters, electricity distributors, natural gas utilities, and rate-regulated electricity generators. As a result, the prescribed ROE decreased by 0.25 percent. 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. The above changes did not affect the prescribed ROE 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 subsequent application for new regulated prices. OPG's December 2025 application for new regulated prices with the OEB includes a proposal to increase the equity component of the deemed capital structure applicable to the Company's rate base.

The December 2025 amendments to *Ontario Regulation 53/05* established a variance account for DNNP LP to record, for future disposition and until the effective date of the OEB's first order setting regulated prices for the DNNP SMR facilities after the DNNP has been completed, the revenue requirement impact of the differences between DNNP LP's actual capital structure and cost of debt, and such capital structure and cost of debt parameters approved by the OEB in setting regulated prices for the DNNP SMRs. The disposition of the balance in the account is subject to the OEB's review of the borrowing costs incurred by DNNP LP.

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.

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); Shareholder equity injections; agencies of the provincial and federal governments; and private placement and other project debt and equity financing arrangements.

Credit Ratings

Maintaining an investment grade credit rating supports OPG's ability to access cost effective financing. As at December 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 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

As Ontario's largest, and one of North America's most diverse electricity generators, the Company's growth strategy is focused on meeting the forecasted increase in provincial electricity demand, while enhancing reliability and energy security in alignment with Ontario's Integrated Energy Plan. Opportunities are evaluated using financial, risk-based analyses and strategic considerations, including the evaluation of partnership opportunities with other entities where aligned with OPG's business objectives.

OPG's growth strategy includes the investment in new generation development and the renewal and expansion of existing assets to meet Ontario's evolving electricity needs. The strategy is anchored in OPG's operational and project expertise across a diversified and growing generation portfolio.

OPG also 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, such as nuclear innovation, transport electrification, low-carbon hydrogen production, battery energy storage systems, hydroelectric pumped storage, and other opportunities.

New Nuclear Generation Development

OPG is preparing for possible development of new large nuclear reactors in Ontario. This includes preparing information for the Wesleyville site Impact Assessment process, as well as continuing to evaluate the suitability of the Company's other existing sites for potential new nuclear energy generation. OPG has also begun preliminary evaluations of available large nuclear reactor technologies. The costs for these activities are recorded, for future recovery, in an existing regulatory account established pursuant to *Ontario Regulation 53/05*, with disposition subject to review by the OEB.

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 First Nations to access information, participate in activities, and share feedback related to a potential new nuclear development project at the Wesleyville site.

Further details on activities being undertaken related to a potential new nuclear development project at the Wesleyville site can be found in the section, *Significant Developments* under the heading, *Initial Project Description for Potential New Nuclear Generation at OPG's Wesleyville Site.*

Nuclear Services Collaboration

In December 2025, Laurentis Energy Partners (LEP), a subsidiary of OPG, together with its subsidiary, Canadian Nuclear Partners S.A., and BWXT Canada Ltd., entered into a long-term owner's engineer contract with Kozloduy NPP-New Builds PLC, a Bulgaria-based nuclear energy company. Pursuant to the contract, the consortium will support the construction of two Westinghouse AP1000 reactor units at Bulgaria's Kozloduy Nuclear Power Plant, including project planning, specialized engineering and project management services.

Medical Isotopes

In May 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. LEP will produce Lu-177 and Y-90, which are used to deliver targeted radionuclide therapy for treating certain cancers and tumors. Lutetium-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

The Company's outlook on operating performance, capital expenditure, and financing and liquidity is outlined below. The outlook may be impacted by a number of factors including finalization of project budgets and timing of project approvals, as well as macro-economic factors and geopolitical events, including tariffs and other trade restrictions, as discussed further in the section, *Risk Management*.

Operating Performance

OPG expects net income for the 2026 year to be lower than the 2025 year, primarily due to the impact of recording the benefit of revenue net of costs from the electricity generated from operating the Pickering GS during the first nine months of 2026 in a regulatory account established by Ontario Regulation 53/05 in order to subsequently return these amounts to customers, an additional three months of electricity generation from the Pickering GS during 2025 and a higher number of planned outage days in the cyclical maintenance schedule for the Darlington GS in 2026. These factors are partially offset by the non-recurring loss recognized in the fourth quarter of 2025 related to the sale of Eagle Creek, the impact of a higher previously approved nuclear base regulated price for 2026 and higher electricity generation from the expected return to service of Unit 4 of Darlington GS from refurbishment in March 2026.

Further details on OPG's plan for continued operation of Units 5 to 8 of the Pickering GS and the associated regulatory account can be found in the section, *Core Business and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability*.

The established OEB-approved regulated prices are expected to continue to provide regulatory certainty for 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 2026, consistent with 2025.

Capital Expenditures

OPG's forecasted capital expenditures for the years 2026 to 2028 are expected to range between $7 billion to $8 billion annually. The 2026 to 2028 forecast is higher than the capital expenditures in 2025, primarily reflecting the advancement of the Pickering Refurbishment project into the execution phase following the Province's approval announced in November 2025 and the continued definition and execution phase activities for the DNNP planned over the next three years. These increases are partly offset by lower capital expenditures resulting from the expected substantial completion of the Darlington Refurbishment project in 2026, the expected completion of the Atura Power's NHC and Napanee BESS development projects in 2026 and the Napanee Combined Cycle GS Expansion Project in 2028.

Financing and Liquidity

The Company expects to generate a lower level of cash flow from operating activities in 2026 compared to 2025, in line with the expected lower net income and reflecting nine months of expected operation of Units 5 to 8 of the Pickering GS compared to a full year in 2025. The level of cash flow from operating activities in 2026 will also be affected by electricity generation volumes at the hydroelectric generating stations across Ontario, 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 2026, inclusive of the impact of equity injections from the Province and the proceeds from the sale of Eagle Creek. Further details of OPG's credit facilities can be found in the section, *Liquidity and Capital Resources* under the heading, *Financing Activities*.

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. As at December 31, 2025, both the Decommissioning Segregated Fund and the Used Fuel Fund are in an overfunded position based on the current approved Ontario Nuclear Funds Agreement (ONFA) reference plan in effect for the years 2022 to 2026 (2022 ONFA Reference Plan). As a result of the overfunded position, volatility of market returns, or changes in the Ontario consumer price index (CPI) that otherwise determine the rate of return for the portion of the Used Fuel Segregated Fund guaranteed by the Province are not expected to cause fluctuations in the earnings on the Nuclear Segregated Funds in the short term. Any volatility is also reduced by the impact of an OEB-authorized regulatory account.

The next ONFA reference plan update is scheduled to be completed at the end of 2026. Changes in funding liability estimates upon an ONFA reference plan update can result in adjustments to the values of Nuclear Segregated Funds assets reported on the consolidated balance sheet, as these values are limited to the cost estimate of the funding liability based on the most recently approved ONFA reference plan, plus a portion of the Decommissioning Segregated Fund surplus that may be directed to the Used Fuel Segregated Fund in certain circumstances. On the consolidated statements of income, these adjustments are recorded as increases or decreases to earnings on the Nuclear Segregated Funds, such that an increase in the funding liability would increase earnings on the Nuclear Segregated Funds and a decrease in the funding liability would decrease earnings on the Nuclear Segregated Funds.

Further details on the Nuclear Segregated Funds can be found in the section, *Significant Accounting Policies and Critical Accounting Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

ENVIRONMENTAL, SOCIAL, GOVERNANCE AND SUSTAINABILITY

OPG recognizes that operating in a manner consistent with environmental, social and governance (ESG) principles is directly connected to business success and is expected by the Company's customers, stakeholders, Rightsholders and Shareholder. In addition to its focus on high standards of workplace health and safety and public safety, as Ontario's largest 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 electricity consumers. A central part of OPG's ESG and sustainability focus is its goal of becoming a global equity, diversity and inclusion (ED&I) best practice leader by 2030.

Health and Safety

OPG's employees and contractors are expected to work in alignment with the Company's health and safety culture, Employee Health and Safety Policy and Safe Operations Policy. OPG's integrated health and safety management systems, operational risk control procedures and contractor management processes ensure continued monitoring of health and safety performance across the Company's facilities and support continuous learning and improvement. OPG has consistently ranked in the top quartile of its comparator Canadian electrical utilities in various safety performance metrics. 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]	**2025**	**2024**
TRIF *(injuries per 200,000 hours)*	**0.09**	0.23
SIIR *(serious injuries per 200,000 hours)*	**0.00**	0.02

[1] Performance is inclusive of OPG and its subsidiaries.

OPG's TRIF and SIIR improved in 2025 compared to 2024. To further strengthen safety performance, the Company continues to implement 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.

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 estimated doses to the public resulting from OPG's nuclear operations were as follows:

Annual public dose estimate	**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.

While the estimated public doses from OPG's nuclear operations for the 2025 operating year will not be finalized until the second quarter of 2026, they are not expected to differ significantly from the 2024 levels.

OPG continues to make investments in waterway public safety and dam safety upgrades around its hydroelectric generating stations and dams. OPG's dam safety program encompasses dam safety, emergency management and public safety around dams in compliance with the Company's 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.

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 and are based on past performance and external benchmarking to promote continual improvement. OPG met or outperformed its 2025 targets for spills, environmental infractions, carbon-14 emissions to air, volume of L&ILW produced, and tritium emissions to air and water.

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 2025, 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 2025, OPG and its conservation partners planted approximately 486,000 native trees and shrubs were planted in 2025. Since 2000, this brings OPG's total tree planting contribution to over 10 million trees, fulfilling the target outlined in the Climate Change Plan.

In December 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 (NERC) standards. OPG's Lennox GS and Atikokan GS and Atura Power's combined cycle plants registered under the CER in 2025. OPG continues to assess the impact of this regulation on its thermal generating facilities and to monitor CER-related developments.

Climate

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, the Canadian Sustainability Standards Board and the Canadian Securities Administrators' proposed mandatory climate-related disclosure requirements.

Additional information about OPG's climate strategy and associated oversight mechanisms can be found in the section, *Description of the Business* under the heading *Environmental, Social, Governance and Sustainability – Environment,* in the AIF. A discussion of climate-related risk management is found in the section, *Risk Management* under the heading, *Risks to Achieving Operational Excellence.*

Carbon Prices

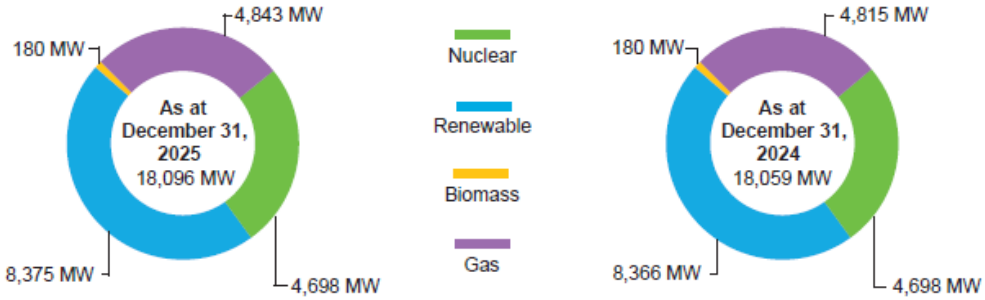
The Canadian federal *Greenhouse Gas Pollution Pricing Act* provides for a price of carbon through an Output-Based Pricing System for industrial facilities and a fuel charge for non-exempt fossil fuel purchases, with the federal carbon price per tonne of carbon dioxide equivalent (CO^2e) emissions increasing 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 program is not expected to have a material financial impact on the Company.

Climate-Related Performance and Key Metrics

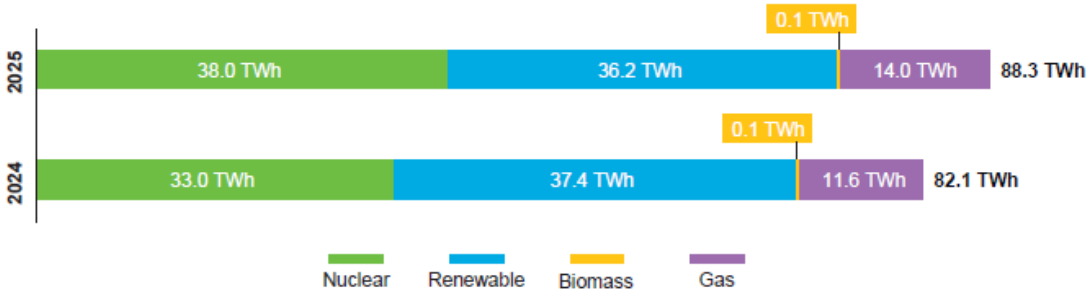
OPG continues to determine the most relevant climate-related impacts for the business in the context of its ESG and Sustainability framework and is engaged in aligning with industry metrics. OPG is in the process of developing such quantitative metrics and targets for climate change as part of an effort to integrate climate considerations into business processes. 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

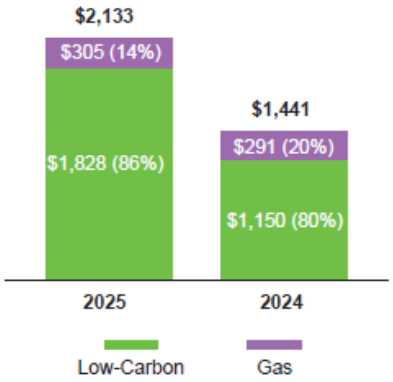
In-service generating capacity by generation type (MW) [1]



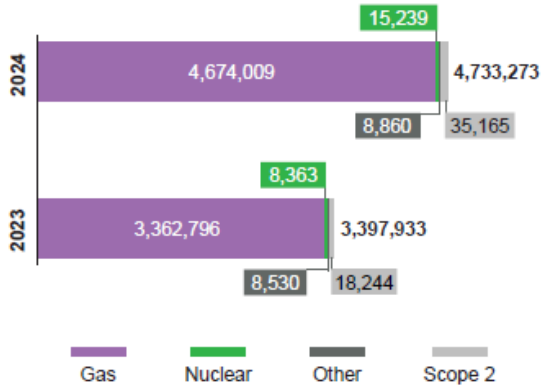
Electricity generation by generation type (TWh) [1]



EBIT from generating stations by facility category (millions of dollars); Climate-related transition risk [1]



Scope 1 and Scope 2 GHG emissions (tonnes CO_2e) [2]



[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. Renewable category includes the Company's hydroelectric and solar generating facilities. Biomass category includes the Atikokan GS, which uses wood pellets from sustainably managed forests. 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 gas generation sources increased as at December 31, 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 [2]	Low-carbon sources accounted for approximately 84 percent of OPG's total electricity generation during 2025, compared to approximately 86 percent 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. For further details, refer to the section, *Highlights* under the heading, *Electricity Generation*.
EBIT from generating stations by facility category; Climate-related transition risk [3]	The portion of EBIT from low-carbon generation increased in 2025, compared to 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*.
Scope 1 GHG emissions – Direct and Emission Rate [4]	The Scope 1 GHG emissions metric identifies direct carbon dioxide equivalent (CO_2e) emissions from OPG's thermal and nuclear operations and other facilities. For the year ended December 31, 2024, 4,674,009 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 [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, 2024, an estimated 35,165 tonnes of CO_2e (2023 – 18,244 tonnes of CO2e) 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 and as a result of increased emissions from the electricity grid.

[1] Identifies capacity available from OPG's different electricity generation sources and tracks low-carbon energy capacity relative to other sources. Nuclear, Renewable and Biomass generating facilities 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 energy generation sources (Nuclear, Renewable and Biomass) relative to other sources.
[4] Scope 1 GHG emissions, Emission Rate and Scope 2 GHG emissions are based on the most recently available estimates.

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 to create social and economic benefits through partnership and collaboration. This includes, where appropriate, pursuing electricity 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.

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 electricity generation-related development partnerships for the years ended December 31:

Indigenous partnerships data	2025	2024
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)*	**290**	263

OPG continues to undertake proactive and ongoing engagement with Indigenous communities in relation to the Company's operations and projects, including early consultation, integration of Indigenous knowledge and perspectives, responsive issue resolution, and long-term relationship building. OPG is actively engaged with multiple Indigenous Nations and communities that hold Aboriginal, Treaty, and Inherent rights or interests in the lands and territories. Throughout 2025, monthly meetings were held to ensure that Indigenous Nations and communities had access to information and opportunities to influence project outcomes where OPG project sites are located, including the DNNP, the Pickering Refurbishment project, and potential new nuclear generation development at the Wesleyville site. In late 2025, OPG signed amended memorandums of understanding with local First Nations to advance potential new nuclear generation development at the Wesleyville site, acknowledging Indigenous territories and emphasizing collaboration.

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, a collaboration between OPG, the Electrical Power Systems Construction Association (EPSCA), Kagita Mikam Aboriginal Employment and Training, building trades unions, and vendor and industry partners, which places Indigenous participants into employment roles in the energy sector. As of December 31, 2025, the ION program exceeded its annual target by 4 placements, with 74 ION participants placed into employment roles. Since the program was launched in 2018, a total of 256 ION participants have been placed into employment roles.

OPG continues to focus on increasing economic impact for Indigenous communities and businesses through its operations, projects and initiatives, including competitive procurement processes. Over the course of 2025, OPG awarded approximately $347 million in contracts to Indigenous businesses and distributed approximately $18 million through equity partnerships with First Nations in Ontario. Since the launch of OPG's Reconciliation Action Plan in 2021, OPG has provided a total of approximately $793 million in such contract awards and equity partnership distributions, representing approximately 79 percent of the Company's goal to commit $1 billion in economic impact to Indigenous communities and businesses over a 10-year period.

Equity, Diversity and Inclusion

OPG is committed to workplace ED&I, at the enterprise and site levels of the organization, 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 high-performing, diverse and committed workforce 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 with a view to building a workforce that represents its communities and ensuring a culture of inclusion.

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. In May 2025, OPG updated its ED&I Strategy actions, building on the prior commitments and introducing new tools and training for leaders, including enhanced interview guides to support inclusive and equitable hiring decisions.

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]	2025 [3]	2024 [3]
Women	29.1%	**24.8%**	24.6%
Indigenous Peoples	2.4%	**2.5%**	2.5%
Racialized People	33.3%	**23.4%**	22.9%
Persons with Disabilities	11.4%	**6.8%**	7.2%

[1] OPG's workforce representation values depend on employees voluntarily self-identifying.
[2] The LMA values shown are from 2024, being the most currently available data.
[3] Workforce representation values include all employment types, including regular and temporary employees.

OPG applies ED&I principles to succession planning and metrics with the goal of ensuring candidate pools for management positions are diverse and equitable. Representation of the four designated groups defined under the *Employment Equity Act* at the Board and senior management level as of December 31, 2025 was as follows:

	Women		Diversity Representation [1]	Total
Directors	**6**	**54.5%**	**54.5%**	**11**
Corporate Officers [2]	**6**	**60.0%**	**90.0%**	**10**
Enterprise Leadership Team [3]	**7**	**63.6%**	**72.7%**	**11**
Senior Leadership Team [4]	**27**	**34.2%**	**53.2%**	**79**

[1] Includes individuals who are members of more than one of the four designated groups; Women, Racialized Persons, Indigenous Peoples, and Persons with Disabilities.
[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 Chief Executive Officer (CEO), C-Suite Officers and Senior Vice Presidents who report directly to the CEO or who may be named to the ELT.
[4] Senior Leadership Team (SLT) generally comprises individuals at the vice president level or equivalent and is exclusive of members from the other reported groups.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

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, and also includes revenue under the terms of a long-term lease arrangement and associated 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 project expenditures for the DNNP and the operating results of DNNP LP.

(millions of dollars – except where noted)	**2025**	**2024**
Electricity generation (TWh)	**38.0**	33.0
Revenue	**4,527**	3,798
Fuel expense	**343**	288
Gross margin	**4,184**	3,510
Operations, maintenance and administration expenses	**1,962**	2,469
Property taxes	**27**	25
Other losses	**14**	9
Earnings before interest, income taxes, depreciation and amortization	**2,181**	1,007
Depreciation and amortization expenses	**782**	665
Earnings before interest and income taxes	**1,399**	342

Earnings before interest and income taxes from the segment increased by $1,057 million in 2025, compared to 2024.

The increase in segment earnings was largely driven by lower OM&A expenses of $507 million, and higher revenue of $500 million as a result of higher electricity generation of 5.0 TWh. The decrease in OM&A expenses was mainly 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 full year impact in 2025 of 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 $63 million in 2025, compared to 2024, excluding amortization expense related to the recovery and repayment of OEB-authorized regulatory account balances, was primarily due to the cessation of commercial operation of Unit 1 and 4 of the Pickering GS in the fourth quarter of 2024, partially offset by higher depreciation expense recognized from placing capital in service.

An increase in revenue in 2025 reflecting the impact of the new rate riders for the 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 these balances.

The planned and unplanned outage days at the Darlington and Pickering nuclear generating stations were as follows:

	2025	2024
Planned Outage Days		
Darlington GS [1]	**25.7**	118.3
Pickering GS	**83.4**	295.6
Unplanned Outage Days		
Darlington GS [1]	**31.0**	88.3
Pickering GS	**48.0**	76.6

[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 during 2025, compared to 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 during 2025, compared to 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 in 2024.

The lower unplanned outage days at the Darlington GS during 2025, compared to 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 during 2025, compared to 2024, were primarily due to fuelling machine recovery activities executed at the station in the first half of 2024.

The Unit Capability Rates for the Darlington and Pickering nuclear generating stations were as follows:

	2025	2024
Unit Capability Rate *(%)* [1, 2]		
Darlington GS	**97.2**	87.0
Pickering GS	**96.7**	96.4

[1] Nuclear Unit Capability Rate excludes unit(s) during the period in which they are undergoing refurbishment.

[2] Effective in the fourth quarter of 2025, the Company replaced the Unit Capability Factor with the Unit Capability Rate as an operating performance measure. For additional details on Unit Capability Rate, refer to the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*.

The Unit Capability Rate at the Darlington GS increased in 2025, compared to 2024, primarily due to fewer unplanned outage days. The Unit Capability Rate at the Pickering GS in 2025 was comparable to 2024.

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 that is generated, 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.

(millions of dollars – except where noted)	**2025**	**2024**
Revenue	**153**	185
Operations, maintenance and administration expenses	**153**	185
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**1,232**	1,210
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(1,138)**	(1,102)
Loss before interest and income taxes	**(94)**	(108)

The segment loss before interest and income taxes decreased by $14 million in 2025 compared to 2024. 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 obligations to reflect the passage of time.

The higher earnings from the Nuclear Segregated Funds were 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 2025 and 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.

As at December 31, 2025, the Decommissioning Segregated Fund was overfunded by approximately 55 percent and, after taking into account the rate of return guarantee provided by the Province, the Used Fuel Segregated Fund was overfunded by approximately 11 percent based on the 2022 ONFA Reference Plan.

Further details on the Nuclear Segregated Funds can be found in the section, *Significant Accounting Policies and Critical Accounting Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

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.

(millions of dollars – except where noted)	**2025**	**2024**
Electricity generation (TWh)	**30.9**	32.5
Revenue [1]	**1,621**	1,571
Fuel expense	**347**	335
Gross margin	**1,274**	1,236
Operations, maintenance and administration expenses	**412**	416
Property tax	**1**	1
Other losses	**20**	11
Earnings before interest, income taxes, depreciation and amortization	**841**	808
Depreciation and amortization expenses	**267**	227
Earnings before interest and income taxes	**574**	581

[1] During 2025 and 2024, the Regulated – Hydroelectric Generation business segment revenue included incentive payments of $53 million and $28 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 decreased by $7 million in 2025, compared to 2024. The decrease in segment earnings was primarily due to 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 in 2025 reflecting the impact of the new rate riders for the 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 these balances.

The Hydroelectric Availability for the generating stations reported in the Regulated – Hydroelectric Generation business segment was as follows:

	2025	**2024**
Hydroelectric Availability *(%)* [1]	**85.5**	85.8

[1] Hydroelectric Availability is defined in the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*.

The Hydroelectric Availability in 2025 was comparable to 2024.

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 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.

Effective January 9, 2026, upon the sale of Eagle Creek, the Company no longer has electricity generation operations or facilities in the United States. The Contracted Hydroelectric and Other Generation business segment comprises only contracted generating facilities in Ontario from that date.

(millions of dollars – except where noted)	**2025**	**2024**
Electricity generation (TWh)	**5.6**	5.0
Revenue	**922**	815
Fuel expense	**112**	59
Gross margin	**810**	756
Operations, maintenance and administration expenses	**288**	307
Accretion on fixed asset removal liabilities	**9**	9
Property taxes	**18**	18
Other losses	**457**	6
Earnings before interest, income taxes, depreciation and amortization	**38**	416
Depreciation and amortization expenses	**148**	174
(Loss) earnings before interest and income taxes	**(110)**	242

Earnings before interest and income taxes from the segment decreased by $352 million in 2025, compared to 2024. The decrease was primarily due to a non-recurring pre-tax loss of $477 million recognized related to the sale of the Eagle Creek business in the United States. The decrease in earnings was partially offset by higher earnings from the Ontario-based facilities, reflecting higher revenue from the Lower Mattagami hydroelectric generating stations and the Lennox GS.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) within the Contracted Hydroelectric and Other Generation business segment were as follows:

	2025	**2024**
Hydroelectric Availability *(%)* [1, 2]	**84.6**	80.8
Thermal EFOR *(%)* [2]	**12.8**	3.8

[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 increased in 2025, compared to 2024, primarily due to fewer planned outages at the Lower Mattagami hydroelectric generating stations.

Thermal EFOR increased in 2025, compared to 2024, primarily due to higher unplanned outage days from forced extension outage events at the Lennox GS.

Atura Power Segment

The Atura Power business segment operates in Ontario, generating and selling electricity from the Company's fleet of combined cycle plants. 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 business development projects.

(millions of dollars – except where noted)	**2025**	**2024**
Electricity Generation (TWh)	**13.8**	11.6
Revenue	**1,143**	871
Fuel expense	**619**	367
Gross margin	**524**	504
Operations, maintenance and administration expenses	**113**	98
Accretion on fixed asset removal liabilities	**2**	2
Property taxes	**2**	2
Other losses	**2**	1
Earnings before interest, income taxes, depreciation and amortization	**405**	401
Depreciation and amortization expenses	**135**	125
Earnings before interest and income taxes	**270**	276

Earnings before interest and income taxes from the segment decreased by $6 million in 2025, compared to 2024. The decrease in earnings was primarily due to higher OM&A expenses, mainly driven by increased business development activities and maintenance activities, and higher depreciation and amortization expenses, mainly from capital placed in service. The decrease was partially offset by a 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:

	2025	**2024**
Thermal Availability *(%)* [1]	**84.6**	85.1

[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 one-year basis.

The Thermal Availability for the combined cycle plants decreased in 2025, compared to 2024, primarily due to planned outages for work performed to execute the IESO-awarded capacity upgrade projects, partially offset by fewer planned and unplanned outages at the Halton Hills and Napanee generating stations.

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, 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 consolidated cash flow position are noted below.

Changes in cash and cash equivalents for 2025 and 2024 were as follows:

(millions of dollars)	**2025**	**2024**
Cash, cash equivalents and restricted cash, beginning of period	**1,363**	1,481
Cash flow provided by operating activities	**3,708**	2,211
Cash flow used in investing activities	**(5,540)**	(3,668)
Cash flow provided by financing activities	**1,800**	1,326
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**(5)**	13
Net increase (decrease) in cash, cash equivalents and restricted cash, including cash classified within current assets held for sale	**(37)**	(118)
Less: cash, cash equivalents and restricted cash classified within current current assets held for sale	**(77)**	-
Cash and cash equivalents and restricted cash, end of period	**1,249**	1,363

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 opportunities.

Cash flow used in investing activities increased by $1,872 million in 2025, compared to 2024, primarily due to higher capital expenditures within the Regulated – Nuclear Generation, Regulated – Hydroelectric Generation and Atura Power business segments.

Financing Activities

As at December 31, 2025, long-term debt outstanding was $11,739 million, with $673 million representing amounts due within one year. Short-term debt outstanding as at December 31, 2025 was $673 million.

Cash flow provided by financing activities increased by $474 million in 2025, compared to 2024, primarily due the issuance of $1 billion of Class B preferred shares to the Province and net issuance of short-term notes during 2025. The increase was partially offset by lower issuance and higher repayments of long-term debt during 2025.

Committed credit facilities and maturity dates as at December 31, 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 [4]	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 December 31, 2025.
[4] Subsequent to December 31, 2025, the facility was transferred to the buyer following the closing of the transaction to sell Eagle Creek on January 9, 2026.

Short-term debt, letters of credit and guarantees as at December 31 were as follows:

(millions of dollars)	**2025**	**2024**
Lower Mattagami Energy Limited Partnership	**170**	215
Corporate commercial paper	**503**	-
Total short-term debt	**673**	215
Letters of credit	**799**	504

As at December 31, 2025, a total of $799 million of letters of credit had been issued (2024 – $504 million). As at December 31, 2025, this included $345 million for the supplementary pension plans, $270 million for general corporate purposes, $76 million for Atura Power, $65 million for Lower Mattagami Energy Limited Partnership, $15 million for OPG Eagle Creek Holdings LLC and its subsidiaries, $14 million for UMH Energy Partnership, $10 million for LEP and its subsidiaries, $3 million for PowerON Energy Solutions LP and $1 million for PSS Generating Station Limited Partnership.

Long-term debt balances as at December 31 were as follows:

(millions of dollars)	**2025**	**2024**
Medium Term Notes payable	**6,550**	5,950
Senior notes payable under OEFC and corporate credit facilities	**2,811**	2,859
Project financing	**2,397**	2,916
Other	**25**	25
Total Long-term debt [1, 2]	**11,783**	11,750

[1] Excludes the impact of fair value premium and unamortized bond issuance fees.
[2] Following the agreement to sell Eagle Creek in October 2025, the carrying value of Eagle Creek's long-term debt was reclassified as liabilities associated with assets held for sale. The outstanding balance as at December 31, 2025 was $296 million, which was transferred to the buyer upon closing of the transaction to sell Eagle Creek on January 9, 2026.

Further details on financing activities during the year can be found in the section *Significant Developments*.

Share Capital

As at December 31, 2025 and 2024, 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.

As at December 31, 2025 and 2024, 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.

As at December 31, 2025, OPG had 1,000,000 Class B preferred shares, series 1 issued and outstanding at a stated value of $1,002 million (nil as at December 31, 2024). OPG is authorized to issue an unlimited number of Class B preferred shares, issuable in series, of which an unlimited number of Class B preferred shares, series 1, has been authorized.

Any issue of new shares is subject to the consent of OPG's shareholder, the Province.

Guarantees and Indemnifications

As part of normal business, OPG and certain of its subsidiaries enter into various agreements to provide financial or performance assurance to third parties. Such agreements include guarantees, indemnifications, standby Letters of Credit and surety bonds.

The Company has entered into certain guarantees and indemnifications, which in aggregate have a maximum potential of future payments totalling $454 million (2024 – $30 million). As at December 31, 2025, in relation to the events covered by these agreements, the Company had recognized $69 million (2024 – nil) in liabilities on the consolidated balance sheets. As current estimates change, additional losses related to guarantees, indemnifications, standby Letters of Credit and surety bonds to third parties, which could be material, may be recorded by the Company in the future.

Contractual Obligations

OPG's contractual obligations as at December 31, 2025 were as follows:

(millions of dollars)	**2026**	**2027**	**2028**	**2029**	**2030**	**Thereafter**	**Total**
Fuel supply agreements	237	273	199	250	273	1,501	2,733
Contributions to the OPG registered pension plan [1]	131	134	-	-	-	-	265
Long-term debt repayment	674	530	5	505	805	9,264	11,783
Interest on long-term debt	453	443	425	425	397	5,520	7,663
Commitments related to Darlington Refurbishment project [2]	65	-	-	-	-	-	65
Commitments related to Atura Power development projects [2]	205	19	8	1	-	-	233
Commitments related to Pickering Refurbishment project [2]	527	-	-	-	-	-	527
Commitments related to Darlington New Nuclear Project [2]	367	-	-	-	-	-	367
Operating licensees	61	63	61	62	59	120	426
Operating lease obligations	22	18	13	13	9	42	117
Other	54	49	44	33	21	360	561
Total	2,796	1,529	755	1,289	1,564	16,807	24,740

[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, 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.

[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. This 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, *Significant Accounting Policies and Critical Accounting Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

Collective Agreements

As at December 31, 2025, OPG and its subsidiaries had approximately 11,360 regular and term-based employees (regular workforce), mostly in Ontario. Most of OPG's regular workforce in Ontario is represented by two unions:

- PWU – As at December 31, 2025, this union represented approximately 5,100 regular and term-based employees, or 45 percent of OPG and its subsidiaries' regular workforce. Union membership includes station operators, technicians, skilled trades, clerical staff and security personnel. The current three-year collective agreement between the PWU and OPG expires on March 31, 2027.

  There are two collective agreements between the PWU and Atura Power, and a collective agreement between the PWU and LEP. On October 28, 2025, a two-year renewal collective agreement expiring on November 16, 2027 was ratified by the PWU-represented employees at the Brighton Beach GS. On May 29, 2025, a three-year renewal collective agreement expiring on December 31, 2027 was ratified by the PWU-represented employees at Atura Power's other facilities. On July 7, 2025, a three-year renewal collective agreement expiring on February 29, 2028 was ratified by the PWU-represented employees of LEP.

- Society – As at December 31, 2025, this union represented approximately 4,300 regular and term-based employees, or 38 percent of OPG and its subsidiaries' regular workforce. Union membership includes supervisors, professional engineers, scientists and other professionals. Following the expiry of the governing collective agreement on December 31, 2025, the Society and OPG received the final arbitration award for a three-year collective agreement on January 26, 2026, covering the period from January 1, 2026 to December 31, 2028.

  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.

Additionally, bargaining rights with the craft unions that perform construction work at OPG's generating facilities are established either through the EPSCA or directly with OPG and its subsidiaries. All such 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.

BALANCE SHEET HIGHLIGHTS

The following section provides other highlights of OPG's 2025 audited consolidated financial position using selected balance sheet data as at December 31:

(millions of dollars)	**2025**	**2024**
Property, plant and equipment – net The increase was primarily due to capital expenditures, partially offset by the reclassification of Eagle Creek's property, plant and equipment (PP&E) to assets held for sale and depreciation expense. Further details on capital expenditures can be found in the section, *Highlights* under the heading, *Capital Expenditures.*	**38,680**	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.	**22,817**	22,412
Short-term debt The increase was primarily due to net issuances of corporate commercial paper.	**673**	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.	**11,739**	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.	**26,665**	26,042
Pension assets The increase was primarily due to the excess of actual returns on pension plan assets over interest costs on the liabilities during 2025 and the remeasurement of the liabilities at the end of 2025 reflecting higher discount rates.	**1,096**	337

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 certain guarantees and long-term contracts.

SIGNIFICANT ACCOUNTING POLICIES AND CRITICAL ACCOUNTING ESTIMATES

OPG's significant accounting policies, including the impact of major recent accounting pronouncements adopted and not yet adopted, are outlined in Note 3 of OPG's 2025 audited consolidated financial statements.

Exemptive Relief for Reporting under US GAAP

In December 2025, 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 in accordance with US GAAP, rather than IFRS, without becoming a US Securities and Exchange Commission registrant. This exemption replaced the previous exemptive relief received by OPG from the OSC in September 2022. The exemption will terminate on the earliest of the following:

- January 1, 2032;
- 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. Four 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.

Critical Accounting Estimates

Certain estimates and judgments are recognized as critical accounting estimates 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 estimates that affect OPG's consolidated financial statements are highlighted below.

Rate Regulated Accounting

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 costs incurred 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, as authorized by the OEB, 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.

It is the Company's position that, based on the OEB's policy for recovery mechanisms for pension and OPEB costs of rate regulated utilities and the outcomes of OPG's previous applications with the OEB, there is sufficient likelihood that unamortized pension and OPEB amounts that have not yet been reclassified from AOCI will be included in future regulated prices.

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 generating 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 the condition and expected remaining 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 remaining 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, overhaul, refurbishment or replacement of 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.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

In accordance with the ONFA, OPG sets aside and invests funds in the Nuclear Segregated 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 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.

Financial Guarantee Requirements and 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

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 Wate 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.

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.

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, 2025 was approximately 5.0 percent**.** This represents an increase compared to the discount rate of approximately 4.7 percent that was used to determine the obligations as at December 31, 2024.

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 2025, with an effective date of January 1, 2025. 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, 2025 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 2025. The results of this valuation were reflected in the 2025 year-end obligations reflecting appropriate assumptions for accounting purposes as at December 31, 2025.

The position of the registered pension plan, for accounting purposes, increased from a surplus of $337 million as at December 31, 2024 to a surplus of $1,096 million as at December 31, 2025. This increase was largely due to the excess of actual return on pension assets values over interest costs on the liabilities during 2025 and a re-measurement of the benefit obligations at the end of 2025 reflecting an increase in the discount rates.

The projected benefit obligations for OPEB plans increased from $2,848 million as at December 31, 2024 to $2,960 million as at December 31, 2025. This increase was largely due to the interest costs on the liabilities during 2025 and the impact of the updated, higher per capita health care claims costs assumption as part of the 2025 actuarial valuation, partially offset by the remeasurement of the benefit obligations at the end of 2025 reflecting an increase in the discount rates at the end of 2025.

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, 2025 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	**(43)**	**n/a**	**n/a**
0.25% decrease	**43**	**n/a**	**n/a**
Discount rate			
0.25% increase	**(12)**	**(1)**	**(11)**
0.25% decrease	**13**	**1**	**11**
Inflation [2]			
0.25% increase	**59**	**1**	**1**
0.25% decrease	**(54)**	**(1)**	**(1)**
Salary increases			
0.25% increase	**15**	**5**	**1**
0.25% decrease	**(16)**	**(4)**	**(1)**
Health care cost trend rate			
1% increase	**n/a**	**n/a**	**64**
1% decrease	**n/a**	**n/a**	**(49)**

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 Obligations

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. OPG will also be responsible for the nuclear waste management and nuclear decommissioning obligations associated with the DNNP SMRs, which, once they arise, will be the responsibility of Ontario Power Generation Inc., pursuant to the lease arrangement with DNNP LP.

To estimate the liability for used nuclear fuel management, OPG uses an approach consistent with the Adaptive Phased Management (APM) concept approved by the Government of Canada, based on technical and financial information developed by the NWMO. The NWMO is responsible for the design and implementation of Canada's plan for the long-term management of used nuclear fuel.

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 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. OPG evaluates underlying assumptions and estimates based on available information.

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, the multiple assumptions involved 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. The cost estimates associated with the APM plan are updated based on information provided by the NWMO. 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 by 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. The Nuclear Liabilities were further updated as of December 31, 2023 to reflect the extension of the accounting end-of-life assumptions for Units 5 to 8 of the Pickering GS.

For the purposes of calculating OPG's Nuclear Liabilities, as at December 31, 2025, 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, 2025 is $26,395 million (2024 – $25,773 million). As at December 31, 2025, the undiscounted estimated future cash flows associated with OPG's Nuclear Liabilities in 2025 dollars are as follows:

(millions of dollars)	**2026**	**2027**	**2028**	**2029**	**2030**	**Thereafter**	**Total**
Expenditures for nuclear fixed asset removal and nuclear waste management [1]	870	612	511	384	342	47,879	50,598

[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 $270 million as at December 31, 2025 (2024 – $269 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 $376 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

For financial instruments, including financial assets 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. OPG's use of financial instruments also 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 Enterprise Risk Management 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, as described in the section, *Core Business and Outlook*, 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 use of artificial intelligence technology by threat actors 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 NERC and the relevant Bulk Power System facilities as determined by the Northeast Power Coordinating Council (NPCC). A subset of these standards establishes the reliability requirements that relate to cyber security. 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 restricted in their capacity to successfully service OPG and other key customers in parallel, given the increased focus on energy infrastructure development in Canada and globally.

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, critical goods and services risks are identified by assessing supply and demand conditions, and mitigation strategies are developed 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, materials availability and geopolitical events including trade disputes that could potentially lead to supply chain disruptions or cost increases.

Tariffs and Other Trade Restrictions

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 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.

Labour Relations

As at December 31, 2025, 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 collective agreement established in the future may include terms that 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 Company's collective agreements, refer to the section, *Significant Developments* under the heading, *Collective Agreement with Society of United Professionals* 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 with a view 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 may 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. 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 revenue, 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.

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 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 completion of the Darlington Refurbishment project and transition to the 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 deep geological repository (DGR). The NWMO has 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 and is advancing the project into the regulatory decision-making process, with DGR operations planned to begin between 2040 and 2045.

In 2023, the Government of Canada accepted the NWMO's ISRW submission. 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 completed by the NWMO. The NWMO is advancing work on the intermediate-level waste strategy through public engagement activities that seek input on the site selection process. In January 2024, the CNSC granted Canadian Nuclear Laboratories a licence authorizing construction of 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 Severe Weather Events

In recent years, Ontario has experienced an increase in changing climate parameters and severe weather events. Changes in precipitation, water and air temperatures, water flows and levels may impact OPG's operations. Additionally, changes in climate can also affect the reliability and life expectancy of major equipment. To mitigate the physical risks posed by severe weather, OPG monitors developments in climate science and adaptation practices, and works with stakeholders to identify and implement adaptation requirements. Adaptation requirements are identified through analysis and by understanding the potential impacts on watersheds, assets, operations and the electricity market. OPG's resilience against these risks is anticipated to increase as adaptation actions are identified and completed. 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. For information on managing risks associated with natural disasters such as flooding and wildfires, refer to the discussion under the heading, *Risks to Achieving Operational Excellence – Business Continuity and Emergency Management.*

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 electricity supply and demand profiles in the regions where OPG operates and impacts on the Company's carbon-based generating technologies.

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, *Description of the Business* under the heading, *Environmental, Social, Governance and Sustainability – Environment,* in the AIF.

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 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 Requirements

OPG is subject to extensive legislation, regulations and oversight by various entities in the jurisdictions in which it operates, including the CNSC, the OEB, and the IESO.

The uncertainty associated with nuclear regulatory compliance requirements 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. Furthermore, pursuant to the obligations set forth in the IESO Market Rules and OPG's electricity generation licence issued by the OEB, the Company's facilities are required to maintain compliance with all applicable NERC Reliability Standards and NPCC Regional Criteria. 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.

Risks related to certain 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. OPG's plans are regularly tested, updated, and 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. Investments in capital projects may also impact OPG's borrowing capacity and credit ratings. OPG mitigates risks associated with project execution through a scalable project management methodology applied to projects across the enterprise. 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.*

Small Modular Reactors

OPG is advancing the construction of SMRs to help meet future electricity needs, with the DNNP's Unit 1 representing 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 construct SMRs at the DNNP site.

Risks associated with the SMR deployment include: uncertainties associated with obtaining regulatory approvals for this 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 rightsholders and other stakeholders. *Ontario Regulation 53/05* prescribes any SMR constructed 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.

For further information on the DNNP, refer to the section, *Significant Developments* under the heading, *Darlington New Nuclear Project* and the section *Core Business and Outlook* under the heading, *Project Excellence – Darlington New Nuclear Project.*

Pickering Refurbishment

In November 2025, the Province announced its approval of OPG's plan to proceed with the refurbishment of Units 5 to 8 at the Pickering GS. This complex megaproject presents inherent cost, schedule and regulatory risks, which will continue to be managed consistent with OPG's enterprise project management approach. Additionally, key risks that may impact the project from the definition phase through to the start of the execution phase, such as skilled trades availability and procurement of long lead materials, are being managed as per the project plan. OPG is leveraging lessons learned from the Darlington Refurbishment project to inform risk and project management activities as the project advances.

Further details can be found in the section, *Significant Developments* under the heading, *Pickering Refurbishment.*

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 DNNP, the Pickering Refurbishment project and refurbishments and redevelopments of hydroelectric generating stations. 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.

Risks to Maintaining Financial Strength

Risks related to macroeconomic 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 safety and security, nuclear waste management and nuclear decommissioning, the electricity market, the environment, trade and taxation, including investment tax credit programs. Governments and regulatory bodies may change or enact legislation, 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 capital 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 changes in environmental regulations resulting in 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 (DFO) to determine practical approaches to the hydroelectric industry's compliance. OPG has developed a compliance strategy and is working with the DFO regarding its implementation.

In October 2025, new Nuclear Security Regulations in Canada were published with increased compliance requirements. OPG is monitoring the CNSC's release of additional detailed requirements to inform the implementation plan and assess cost impacts of compliance.

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 and establishes requirements for the government to set interim national emission targets. In December 2024, the Government of Canada released the CER, which may limit operations of OPG's thermal generating stations beyond 2035. 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, *Description of the Business* under the heading, *Environmental, Social, Governance and Sustainability – Environment,* in the AIF.

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 draft CEITC legislation. The draft legislation currently requires approval from the Senate of the Parliament of Canada before achieving Royal Assent. Should these tax credits ultimately not be available to OPG, the Company would 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, for example:

- In setting regulated prices, the OEB makes adjustments to forecasts submitted by OPG, disallows recovery of incurred capital costs or defers recovery of a material portion of an approved revenue requirement;
- 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 differ significantly 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 repayment 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 on a timely basis.

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, including as the NWMO progresses the project to construct Canada's DGR for used nuclear fuel. 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 next ONFA reference plan update is scheduled to be completed at the end of 2026.

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, 2025, 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 employee contribution levels; 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, Class A shares and Class B preferred shares. Accordingly, the Province, as represented by the Ontario Ministry of Energy and Mines, 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 with the OEB, 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 the 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 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, 2025:

	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	**40**	**28**	**5**	**18**
IESO [4]	**5**	**621**	**1**	**612**
Other	**34**	**3**	**2**	**2**
Total	**79**	**652**	**8**	**632**

[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.

	2026	2027	2028
Estimated fuel requirements hedged *(%)* [1]	77	83	72

[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, 2025, OPG had nil in foreign exchange contracts outstanding.

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. Growth in Ontario's electricity demand may be impacted by geopolitical or economic factors including changes in the trade and tariffs environment. For further information, see *Risks to Achieving Operational Excellence – Tariffs and Other Trade Restrictions*.

Revenue from OPG's generating assets prescribed for regulation by the OEB is largely not impacted by Ontario wholesale electricity prices. All of OPG's non-regulated assets in Ontario are subject to ESAs with the IESO, which are designed to provide for recovery of costs and a return on invested capital.

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, individually and in the aggregate, 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 perspectives of various stakeholders, including electricity consumers, local communities and government agencies, Rightsholders 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 Peoples 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 Company's operations 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 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:

	2025		2024	
(millions of dollars)	**Income**	**Expense**	**Income**	**Expense**
Hydro One				
Electricity sales	**24**	**-**	18	-
Services	**-**	**12**	-	9
Dividends	**4**	**-**	5	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**811**	-	1,137
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**1,063**	-	1,459
Hydroelectric gross revenue charge	**-**	**117**	-	118
OEFC				
Hydroelectric gross revenue charge	**-**	**219**	-	223
Interest expense on long-term notes	**-**	**87**	-	88
Income taxes	**-**	**548**	-	377
Property taxes	**-**	**14**	-	13
IESO				
Electricity related revenue	**7,698**	**-**	6,473	-
Fair Hydro Trust				
Interest income	**33**	**-**	33	-
	7,759	**2,871**	6,529	3,424

[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, 2025 and 2024, the Nuclear Segregated Funds were reported net of amounts due to the Province of $12,110 million and $10,236 million, respectively.

Balances between OPG and its related parties as at December 31 were as follows:

(millions of dollars)	**2025**	**2024**
Receivables from related parties		
Hydro One	**3**	3
IESO – Electricity related receivables	**621**	608
Fair Hydro Trust	**4**	4
Province of Ontario	**-**	1
Loan receivable		
Fair Hydro Trust	**899**	902
Accounts payable, accrued charges and other payables		
Hydro One	**1**	3
OEFC	**91**	85
Province of Ontario	**7**	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 December 31, 2025, the Nuclear Segregated Funds held $1,764 million of Province of Ontario bonds (2024 – $1,740 million) and $5 million of Province of Ontario treasury bills (2024 – $8 million). As of December 31, 2025, the OPG registered pension plan held $302 million of Province of Ontario bonds (2024 − $327 million) and $2 million of Province of Ontario treasury bills (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.

In addition, as at December 31, 2025, OPG held $170 million of Hydro One shares (2024 – $159 million).

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 (ICFR). 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. ICFR 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 ICFR during the year ended December 31, 2025 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, 2025, OPG's DC&P and ICFR, 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 2025	2024
Revenue	**2,100**	1,838
Fuel expense	**396**	289
Operations, maintenance and administration expenses	**784**	833
Depreciation and amortization expenses	**343**	335
Accretion on fixed asset removal and nuclear waste management funds	**309**	307
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(290)**	(280)
Other net expenses	**415**	38
Earnings before interest and income taxes	**143**	316
Net interest expense	**46**	42
Income tax expense	**111**	42
Net (loss) income	**(14)**	232
Net (loss) income attributable to the Shareholder	**(19)**	228
Net income attributable to non-controlling interest [1]	**5**	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 loss attributable to the Shareholder for the fourth quarter was $19 million, compared to net income of $228 million for the same quarter in 2024. Earnings before interest and income taxes were $143 million for the fourth quarter of 2025, representing a decrease of $173 million compared to the same quarter in 2024.

Significant factor that decreased EBIT:

- Lower EBIT of $422 million from the Contracted Hydroelectric and Other Generation business segment, primarily due to a non-recurring pre-tax loss of $477 million recognized related to the sale of Eagle Creek, partially offset by higher earnings from the US operations due to cessation of the depreciation and amortization expense as a result of classifying Eagle Creek as held for sale, and lower OM&A expenses.

Significant factors that increased EBIT:

- A gain of $108 million recorded in the fourth quarter of 2025 within the Other category related to changes in the fair market value of non-core equity investments;
- Higher revenues of $43 million from the Regulated – Nuclear Generation business segment, as a result of higher electricity generation of 0.5 TWh; and
- Lower OM&A expenses of $28 million from the Regulated – Nuclear Generation business segment, mainly due to the cessation of commercial operation of Unit 4 of the Pickering GS on December 31, 2024 and lower expenditures as a result of fewer outage days at the Darlington GS.

Net interest expense for the fourth quarter of 2025 was comparable to the same period in 2024.

Income tax expense increased by $69 million during the fourth quarter of 2025, compared to the same quarter in 2024. The increase was primarily due to certain tax adjustments recorded in the fourth quarter of 2025, partially offset by the impact of lower earnings before income taxes compared to the same period in 2024.

Electricity Generation

OPG's electricity generation for the three months ended December 31, 2025 and 2024 was as follows:

(TWh)	Three Months Ended December 31 2025	2024
Regulated – Nuclear Generation	**8.6**	8.3
Regulated – Hydroelectric Generation	**6.8**	7.9
Contracted Hydroelectric and Other Generation [1]	**1.1**	1.2
Atura Power	**4.1**	3.0
Total OPG electricity generation	**20.6**	20.4

[1] Includes OPG's proportionate share of electricity generation from co-owned and minority shareholdings in electricity generating facilities.

The increase in OPG's total electricity generation of 0.2 TWh during the fourth quarter of 2025, compared to the same quarter in 2024, was primarily due to higher electricity generation from the Atura Power business segment, primarily due to higher demand for electricity generation from the combined cycle plants, and higher electricity generation from the Regulated – Nuclear Generation business segment, primarily due to a full three-month period of electricity generation from Unit 1 of the Darlington GS in 2025 following its return to service from refurbishment in November 2024. The increase was partially offset by lower electricity generation from the Regulated – Hydroelectric Generation business segment, primarily due to lower water inflow conditions across most of Ontario during the fourth quarter of 2025.

Ontario's electricity demand as reported by the IESO was 36.7 TWh during the fourth quarter of 2025, compared to 35.0 TWh for the same period in 2024, excluding electricity exports out of the province.

Liquidity and Capital Resources

Cash flow provided by operating activities during the three months ended December 31, 2025 was $618 million, compared to $429 million for the same period in 2024. The increase was primarily due to higher revenue receipts from the Regulated – Nuclear Generation business segment and lower OM&A expenditures, partially offset by lower revenue receipts from the Regulated – Hydroelectric Generation business segment and higher income tax installment payments.

Cash flow used in investing activities was $1,611 million during the three months ended December 31, 2025, compared to $992 million during the same period in 2024. This increase was primarily due to higher capital expenditures within the Regulated – Hydroelectric Generation business segment, for the Pickering Refurbishment project and the DNNP within the Regulated – Nuclear Generation business segment, and within the Atura Power business segment during the fourth quarter of 2025.

Cash flow provided by financing activities increased by $294 million during the three months ended December 31, 2025, compared to the same period in 2024. The increase was primarily due to the $1 billion issuance of Class B preferred shares to the Province, mainly offset by a net repayment of short-term debt and lower 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)	**2025**	**2024**	**2023**
Revenue	**8,355**	7,187	7,434
Net income attributable to the Shareholder	**1,509**	988	1,741
Earnings per share, attributable to the Shareholder *(dollars)*	**$5.49**	$3.60	$6.34
Total assets	**74,778**	69,313	65,688
Total long-term liabilities	**45,651**	44,381	42,434
Weighted average common shares outstanding *(millions)*	**274.6**	274.6	274.6

Quarterly Financial Information

	2025 Quarters Ended				
(millions of dollars – except where noted) *(unaudited)*	**December 31**	**September 30**	**June 30**	**March 31**	**Total**
Electricity generation (*TWh*)	**20.6**	**22.3**	**21.9**	**23.5**	**88.3**
Revenue	**2,100**	**2,066**	**2,032**	**2,157**	**8,355**
Net (loss) income	**(14)**	**486**	**547**	**509**	**1,528**
Less: Net income attributable to non-controlling interest	**5**	**4**	**6**	**4**	**19**
Net (loss) income attributable to the Shareholder	**(19)**	**482**	**541**	**505**	**1,509**
(Loss) Earnings per common share, attributable to the Shareholder *(dollars)*	**($0.08)**	**$1.76**	**$1.97**	**$1.84**	**$5.49**

	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 common share, attributable to the Shareholder *(dollars)*	$0.83	$1.38	$0.58	$0.80	$3.60

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 Rate

The nuclear Unit Capability Rate is a key measure of nuclear generating station performance. It measures the amount of energy that the generating unit(s) generates 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, adjusted for planned energy losses. Capability rates are primarily affected by unplanned outages. An outage day represents a single generating unit being offline or derated for an amount of time equivalent to one day. By industry definition, capability rates exclude production losses beyond plant management's control, such as grid-related unavailability. The nuclear Unit Capability Rate also excludes unit(s) during the period in which they are undergoing refurbishment.

OPG previously reported a nuclear Unit Capability Factor, which included the impact of both planned and unplanned outages but was otherwise determined in the same manner as the Unit Capability Rate. The Unit Capability Rate adjusts for the impact of planned outages by eliminating the planned energy losses. OPG believes that this approach provides a clearer view of a unit's underlying reliability and operational performance by focusing on factors within plant management's control and excluding scheduled maintenance periods. The nuclear Unit Capability Rate presentation also aligns with the updated WANO Nuclear Performance Index methodology.

Hydroelectric Availability

Hydroelectric Availability represents the percentage of time a generating unit at OPG's hydroelectric generating stations 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 thermal generating 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.

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. 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.

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2025

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
Chief Administrative Officer

March 12, 2026

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, 2025 and 2024, 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, 2025 and 2024, 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 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 Company 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 12, 2026

Chartered Professional Accountants
Licensed Public Accountants

CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31 *(millions of dollars except where noted)*	**2025**	**2024**
Revenue	**8,355**	7,187
Fuel expense	**1,421**	1,049
Gross margin	**6,934**	6,138
Operations, maintenance and administration expenses	**2,816**	3,318
Depreciation and amortization expenses *(Note 5)*	**1,413**	1,270
Accretion on fixed asset removal and nuclear waste management liabilities *(Note 10)*	**1,243**	1,221
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 10)*	**(1,138)**	(1,102)
Property taxes	**49**	50
	4,383	4,757
Income before other losses, interest and income taxes	**2,551**	1,381
Other losses *(Note 19)*	**376**	19
Income before interest and income taxes	**2,175**	1,362
Net interest expense *(Note 8)*	**194**	186
Income before income taxes	**1,981**	1,176
Income tax expense *(Note 11)*	**453**	170
Net income	**1,528**	1,006
Net income attributable to the Shareholder	**1,509**	988
Net income attributable to non-controlling interest	**19**	18
Basic and diluted earnings per common share *(dollars) (Note 17)*	**5.49**	3.60

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31 *(millions of dollars)*	**2025**	**2024**
Net income	**1,528**	1,006
Other comprehensive (loss) income, net of income taxes *(Note 12)*		
Actuarial gain, net of past service costs, on remeasurement of liabilities for pension and other post-employment benefits [1]	**36**	41
Reclassification to income of amounts related to pension and other post-employment benefits [2]	**(2)**	(2)
Reclassification to income of amounts related to derivatives designated as cash flow hedges [3]	**3**	(5)
Net gain on derivatives designated as cash flow hedges [4]	**1**	1
Currency translation adjustment	**(101)**	173
Other comprehensive (loss) income for the year	**(63)**	208
Comprehensive income	**1,465**	1,214
Comprehensive income attributable to the Shareholder	**1,446**	1,196
Comprehensive income attributable to non-controlling interest	**19**	18

[1] Net of income tax expense of $9 million and $13 million for 2025 and 2024, respectively.
[2] Net of income tax expense of nil for each of 2025 and 2024.
[3] Net of income tax expense of $1 million and net of income tax recovery of $2 million for 2025 and 2024, respectively.
[4] Net of income tax expense of $1 million and nil for 2025 and 2024, respectively.

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(millions of dollars)*	2025	2024
Operating activities		
Net income	**1,528**	1,006
Adjust for non-cash items:		
Depreciation and amortization expenses *(Note 5)*	**1,413**	1,270
Accretion on fixed asset removal and nuclear waste management liabilities	**1,243**	1,221
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(1,138)**	(1,102)
Pension and other post-employment benefit costs *(Note 13)*	**314**	361
Deferred income tax expense *(Note 11)*	**13**	39
Regulatory assets and regulatory liabilities	**(185)**	(23)
Other losses	**385**	22
Other	**25**	(19)
Expenditures on fixed asset removal and nuclear waste management	**(891)**	(529)
Reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management	**721**	252
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	**(298)**	(342)
Net changes to other long-term assets and long-term liabilities	**34**	116
Net changes in non-cash working capital balances *(Note 21)*	**544**	(61)
Cash flow provided by operating activities	**3,708**	2,211
Investing activities		
Investment in property, plant and equipment and intangible assets *(Note 19)*	**(5,551)**	(3,537)
Proceeds from sale of interest in joint venture	**11**	-
Acquisition of Lightstar Renewables and Lightstar Operations One	**-**	(131)
Cash flow used in investing activities	**(5,540)**	(3,668)
Financing activities		
Issuance of short-term debt	**4,128**	2,960
Repayment of short-term debt	**(3,866)**	(2,945)
Issuance of long-term debt *(Note 8)*	**1,169**	1,930
Repayment of long-term debt *(Note 8)*	**(623)**	(603)
Issuance of Class B shares *(Note 16)*	**1,000**	-
Equity investment from non-controlling interest	**10**	3
Distribution to non-controlling interest	**(18)**	(19)
Cash flow provided by financing activities	**1,800**	1,326
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**(5)**	13
Net decrease in cash, cash equivalents and restricted cash, including amounts classified within current assets held for sale	**(37)**	(118)
Less: cash, cash equivalents and restricted cash classified within current assets held for sale	**(77)**	-
Net decrease in cash, cash equivalents and restricted cash	**(114)**	(118)
Cash, cash equivalents and restricted cash, beginning of year	**1,363**	1,481
Cash, cash equivalents and restricted cash, end of year	**1,249**	1,363

See accompanying notes to the consolidated financial statements.

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	2025	2024
Assets		
Current assets		
Cash, cash equivalents and restricted cash *(Note 4)*	**1,249**	1,363
Equity securities *(Note 20)*	**170**	159
Receivables from related parties *(Note 20)*	**628**	616
Nuclear fixed asset removal and nuclear waste management funds *(Note 10)*	**145**	283
Fuel inventory	**330**	297
Materials and supplies	**145**	145
Regulatory assets *(Note 6)*	**540**	540
Prepaid expenses	**210**	292
Other current assets	**250**	388
Assets held for sale *(Note 23)*	**2,322**	-
	5,989	4,083
Property, plant and equipment *(Note 5)*	**54,509**	51,290
Less: accumulated depreciation	**15,829**	15,159
	38,680	36,131
Intangible assets *(Note 5)*	**791**	1,029
Less: accumulated amortization	**440**	439
	351	590
Goodwill *(Note 7)*	**-**	230
Other assets		
Nuclear fixed asset removal and nuclear waste management funds *(Note 10)*	**22,672**	22,129
Loan receivable from related party *(Note 20)*	**899**	902
Long-term materials and supplies	**385**	355
Regulatory assets *(Note 6)*	**4,348**	4,367
Pension assets *(Note 13)*	**1,096**	337
Other long-term assets	**358**	189
	29,758	28,279
	74,778	69,313

See accompanying notes to the consolidated financial statements.

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	2025	2024
Liabilities		
Current liabilities		
Accounts payable, accrued charges and other payables	**2,682**	2,068
Short-term debt *(Note 9)*	**673**	215
Long-term debt due within one year *(Note 8)*	**673**	604
Regulatory liabilities *(Note 6)*	**246**	246
Liabilities associated with assets held for sale (*Note 23)*	**567**	-
	4,841	3,133
Long-term debt *(Note 8)*	**11,066**	11,103
Other liabilities		
Fixed asset removal and nuclear waste management liabilities *(Note 10)*	**26,665**	26,042
Pension liabilities *(Note 13)*	**381**	383
Other post-employment benefit liabilities *(Note 13)*	**2,815**	2,716
Long-term accounts payable and accrued charges	**306**	382
Deferred revenue	**346**	355
Deferred income taxes *(Note 11)*	**2,521**	2,461
Regulatory liabilities *(Note 6)*	**1,551**	939
	34,585	33,278
Equity		
Common shares [1] *(Note 16)*	**5,126**	5,126
Class A shares [2] *(Note 16)*	**787**	787
Class B preferred shares [3] *(Note 16)*	**1,002**	-
Contributed surplus	**26**	28
Retained earnings	**16,976**	15,469
Accumulated other comprehensive income *(Note 12)*	**130**	193
Equity attributable to the Shareholder	**24,047**	21,603
Equity attributable to non-controlling interest	**239**	196
Total equity	**24,286**	21,799
	74,778	69,313

[1] 256,300,010 common shares outstanding at a stated value of $5,126 million as at December 31, 2025 and 2024.
[2] 18,343,815 Class A shares outstanding at a stated value of $787 million as at December 31, 2025 and 2024.
[3] 1,000,000 Class B preferred shares outstanding at a stated value of $1,002 million as at December 31, 2025 (2024 – nil).

Commitments and contingencies *(Notes 8, 9, 11, 13 and 18)*

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)*	**2025**	**2024**
Common shares *(Note 16)*	**5,126**	5,126
Class A shares *(Note 16)*	**787**	787
Class B preferred shares *(Note 16)*		
Balance at beginning of year	**-**	-
Issuance of Class B preferred shares	**1,000**	-
Paid-in-kind dividends	**2**	-
Balance at end of year	**1,002**	-
Contributed surplus		
Balance at beginning of year	**28**	30
Reclassification to income of amounts related to gain on deconsolidation of Fair Hydro Trust	**(2)**	(2)
Balance at end of year	**26**	28
Retained earnings		
Balance at beginning of year	**15,469**	14,481
Net income attributable to the Shareholder	**1,509**	988
Paid-in-kind dividends	**(2)**	-
Balance at end of year	**16,976**	15,469
Accumulated other comprehensive income, net of income taxes *(Note 12)*		
Balance at beginning of year	**193**	(15)
Other comprehensive (loss) income	**(63)**	208
Balance at end of year	**130**	193
Equity attributable to the Shareholder	**24,047**	21,603
Equity attributable to non-controlling interest		
Balance at beginning of year	**196**	182
Net income attributable to non-controlling interest	**19**	18
Equity investment from non-controlling interest *(Note 22)*	**42**	15
Distribution to non-controlling interest	**(18)**	(19)
Balance at end of year	**239**	196
Total equity	**24,286**	21,799

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, 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 owned and operated through the Company’s wholly-owned subsidiary operating as Atura Power. Through the Company’s wholly-owned subsidiary, DNNP LP, OPG is constructing the first grid-scale small modular reactor (SMR) on the Darlington New Nuclear Project (DNNP) site in Ontario, Canada. In December 2025, DNNP LP entered into a lease arrangement with Ontario Power Generation Inc. with respect to the DNNP and reimbursed Ontario Power Generation Inc. for capital expenditures on the DNNP incurred to date.

As at December 31, 2025, through a wholly-owned subsidiary based in the United States of America (United States or US), OPG wholly or jointly owned and operated, and held minority interests in hydroelectric and solar electricity generation and development assets in the US (Eagle Creek). In October 2025, OPG entered into an agreement to sell Eagle Creek. The transaction closed on January 9, 2026, resulting in the Company no longer having electricity generation operations or facilities in the United States. Further details regarding the transaction can be found in Note 23.

In addition, as at December 31, 2025, OPG owned two nuclear generating stations in Ontario, Canada, 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, and operated by, 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, 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 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 December 2025, 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, 2032;
- 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. Four 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 2024 comparative amounts have been reclassified from consolidated financial statements previously presented to conform to the 2025 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.

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.

Nuclear Waste Management Organization

In 2002, OPG and other Canadian used nuclear fuel producers established a separately incorporated Nuclear Waste Management Organization (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, inventories and the fair value of assets and liabilities held for sale. 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.

Following the agreement to sell Eagle Creek in October 2025, goodwill attributable to Eagle Creek was written down to nil. The assets were subsequently derecognized on January 9, 2026 upon closing of the sale transaction. Further details on the transaction can be found in Note 23.

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, 2025, the amortization periods of major application and computer software ranged from three to five years. Power purchasing contracts acquired through business combinations are initially recognized at fair value, and subsequently amortized on a straight-line basis over the remaining terms of the respective contracts.

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, 2025, the depreciation periods of PP&E were as follows:

Nuclear generating stations and major components	5 to 71 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, 2025, 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 generating 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 the condition and expected remaining 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 remaining operating lives of major life-limiting components are established through technical assessments of their fitness-for-service. Expectations of the 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

Ontario Regulation 53/05 under the *Ontario Energy Board Act, 1998* (*Ontario Regulation 53/05*) provide that OPG receives regulated prices for electricity generated from the Darlington and Pickering nuclear generating stations, the 54 prescribed hydroelectric generating stations, and any SMRs located on the DNNP site. OPG's regulated prices for these facilities are determined by the Ontario Energy Board (OEB).

The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Ontario Ministry of Energy and Mines and regulates market participants in Ontario's natural gas and electricity industries. The OEB is a self-funding Crown corporation. The OEB's mandate and authority come from the *Ontario Energy Board Act, 1998*, the *Electricity Act, 1998* and a number of other provincial statutes.

In December 2025, the Province amended *Ontario Regulation 53/05* to prescribe DNNP LP as a new OEB rate regulated electricity generator, subject to the OEB's satisfaction that DNNP LP has met certain conditions. Ontario Power Generation Inc. and DNNP LP are Ontario's only electricity generators subject to rate regulation by the OEB. Further details on the December 2025 amendments to *Ontario Regulation 53/05* can be found in Note 6.

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 costs incurred 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, as authorized by the OEB, 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.

It is the Company's position that, based on the OEB's policy for recovery mechanisms for pension and OPEB costs of rate regulated utilities and the outcomes of OPG's previous applications with the OEB, there is sufficient likelihood that unamortized pension and OPEB amounts that have not yet been reclassified from AOCI will be included in future regulated prices.

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 as of January 1, 2022 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.

The base regulated prices for nuclear electricity generation (nuclear base regulated price) in effect as of January 1, 2022 have been set under a custom incentive regulation framework, based on an OEB-approved nuclear revenue requirement and production forecast for each year. 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. Consistent with the requirements of *Ontario Regulation 53/05* applicable to the Darlington Refurbishment project period, in setting the nuclear base regulated prices effective January 1, 2022, the OEB deferred, in certain years of the 2022-2026 period, a portion of the approved annual nuclear revenue requirements for future collection in the Rate Smoothing Deferral Account. 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 6.

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 using an incentive rate making methodology, by annually escalating the hydroelectric base regulated prices that had been previously established using a forecast cost-of-service approach, with some adjustments, using an approved formula equal to an inflation factor based on indices published annually by the OEB, less a stretch factor adjustment.

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 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 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 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 waste (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. The significant assumptions underlying operational and technical factors and other assumptions underlying these estimates could change significantly over time and may result in material changes that 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 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 by 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. 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, in connection with the existing facilities, 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 determined based on periodically updated reference plans as 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 15, with realized and unrealized gains and losses recognized in OPG's consolidated statements of income.

p) Financial Instruments and Derivatives

All financial assets and financial liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; and available-for-sale. Financial assets and financial liabilities classified as held-for-trading are measured at fair value. All other financial assets and financial liabilities are measured at amortized cost. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. Accounts receivable are written-off when they are deemed uncollectible. All financial instrument transactions are recorded at trade date.

Long-term debt is measured at fair value less transaction costs on inception, and at amortized cost using the effective interest method thereafter, adjusted for the amortization or accretion of premiums or discounts.

Transaction costs that are directly attributable to the acquisition of financial assets are accounted for as part of the asset's carrying value at inception. Transaction costs related to a recognized debt liability are presented in the consolidated balance sheets as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts and premiums. Costs of arranging the Company's revolving credit facilities are recorded in other assets. Deferred financing costs, premiums and discounts on long-term debt are amortized using the effective interest method while deferred financing costs relating to the revolving credit facilities are amortized on a straight-line basis over the term of the respective instrument.

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 14 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 15 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, using appropriate valuation techniques as outlined in Note 15, 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 a subsidiary located in Romania, 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 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. Subsequent to December 31, 2025, OPG completed the transaction to sell Eagle Creek. Refer to Note 23 for further details on the transaction.

t) Leases

The Company determines if an arrangement is, or contains, a lease at the inception date of the arrangement. 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 higher discount rate decreases the benefit obligations and decreases 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 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.

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 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.

Where defined benefit costs are eligible for capitalization, only the service cost component is capitalized.

v) Preferred Shares

The Company's preferred shares are classified as equity, given they have no fixed redemption date and cannot be redeemed at the holder's sole direction. Holders of the preferred shares are entitled to receive fixed cumulative preferential paid-in-kind (PIK) dividends, either by increasing the liquidation preference or through the issuance of additional preferred shares, as determined by OPG's Board of Directors. PIK dividends are recorded as an increase to the carrying value of the preferred stock and a reduction to retained earnings. Refer to Note 16 for further details on OPG's share capital structure.

w) Non-Controlling Interests

Non-controlling interests represent the portion of equity ownership in subsidiaries that is not attributable to the Shareholder. Non-controlling interests are initially recorded at fair value and subsequently adjusted for the proportionate share of net income (loss) and OCI attributable to the non-controlling interests and any distributions paid to the non-controlling interests.

x) 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 in Canada.

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.

y) Implementation of Accounting Standard Updates

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* 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 is effective for annual periods beginning after December 15, 2024.

The revised guidance was adopted by OPG effective January 1, 2025, with the comparative period information updated accordingly. The adoption of the standard update did not have a material impact on the disclosures contained in the Company's consolidated financial statements.

z) Recent Accounting Pronouncements Not Yet Adopted

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. OPG is currently evaluating the impact of adoption of the standard update on the disclosures contained within its 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 VIE 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.

Accounting for Government Grants Received by Business Entities

In December 2025, the FASB issued ASU 2025-10, *Accounting for Government Grants Received by Business Entities*, an update to Topic 832, *Government Grants*. The update establishes authoritative guidance on the accounting for government grants received by business entities with the purpose of improving financial reporting by clarifying the appropriate accounting, reducing diversity in practice and increasing consistency across business entities. The update is effective for fiscal years beginning after December 15, 2028, 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.

4. CASH, CASH EQUIVALENTS AND RESTRICTED CASH

Cash, cash equivalents and restricted cash as at December 31 were as follows:

(millions of dollars)	**2025**	**2024**
Cash and cash equivalents	**1,249**	1,351
Restricted cash	**-**	12
Total cash, cash equivalents and restricted cash	**1,249**	1,363

As at December 31, 2025, OPG held no restricted cash.

5. PROPERTY, PLANT AND EQUIPMENT, INTANGIBLE ASSETS AND DEPRECIATION AND AMORTIZATION

PP&E as at December 31 were as follows:

(millions of dollars)	**2025**	**2024**
Nuclear generating stations	**24,355**	23,888
Regulated hydroelectric generating stations	**11,709**	11,352
Contracted hydroelectric and other generating stations	**5,367**	7,696
Atura Power generating stations	**3,849**	3,562
Other property, plant and equipment	**741**	475
Construction in progress	**8,488**	4,317
	54,509	51,290
Less: accumulated depreciation		
Generating stations	**15,560**	14,911
Other property, plant and equipment	**269**	248
	15,829	15,159
	38,680	36,131

Construction in progress as at December 31 was as follows:

(millions of dollars)	**2025**	**2024**
Darlington Refurbishment Project	**1,792**	1,110
Darlington New Nuclear Project	**1,949**	971
Pickering Refurbishment Project	**1,910**	387
Nuclear generating stations excluding Darlington Refurbishment, Pickering and Darlington New Nuclear Projects	**794**	671
Regulated hydroelectric generating stations	**757**	398
Contracted hydroelectric and other generating stations	**57**	140
Atura Power generating stations	**989**	426
Other	**240**	214
	8,488	4,317

Interest capitalized to construction in progress during 2025 was $181 million (2024 – $136 million), at an average rate of approximately four percent (2024 – approximately four percent).

Intangible assets as at December 31 were as follows:

(millions of dollars)	**2025**	**2024**
Nuclear generating stations	**126**	107
Regulated hydroelectric generating stations	**9**	8
Contracted hydroelectric and other generating stations	**11**	332
Atura Power generating stations	**126**	126
Computer software and other intangible assets	**468**	400
Development in progress	**51**	56
	791	1,029
Less: accumulated amortization		
Generating stations	**125**	185
Computer software and other intangible assets	**315**	254
	440	439
	351	590

Depreciation and amortization expenses, including amounts recognized in regulatory accounts and the amortization of regulatory assets and regulatory liabilities, for the years ended December 31 were as follows:

(millions of dollars)	**2025**	**2024**
Depreciation	**1,061**	1,281
Amortization of intangible assets	**77**	65
Amounts recognized in regulatory variance and deferral accounts	**(19)**	(161)
Amortization of regulatory assets and regulatory liabilities *(Note 6)*	**294**	85
	1,413	1,270

6. REGULATORY ASSETS AND REGULATORY LIABILITIES

The regulatory assets and regulatory liabilities as at December 31 were as follows:

(millions of dollars)	**2025**	**2024**
Regulatory assets		
Deferral and variance accounts authorized by the OEB or *Ontario Regulation 53/05*		
Rate Smoothing Deferral Account	**702**	677
Nuclear Liability Deferral Account	**447**	520
Capacity Refurbishment Variance Account	**442**	460
Pickering B Variance Account	**349**	131
Hydroelectric Surplus Baseload Generation Variance Account	**214**	307
Pension & OPEB Cash Versus Accrual Differential Deferral Account	**166**	376
Nuclear Development Variance Account	**128**	85
Other deferral and variance accounts [1]	**178**	174
	2,626	2,730
Deferred Income Taxes *(Note 11)*	**2,262**	2,151
Other	**-**	26
Total regulatory assets	**4,888**	4,907
Less: current portion	**540**	540
Non-current regulatory assets	**4,348**	4,367
Regulatory liabilities		
Deferral and variance accounts authorized by the OEB or *Ontario Regulation 53/05*		
Pension and OPEB Cost Variance Account	**395**	411
Pension & OPEB Cash Payment Variance Account	**218**	321
Bruce Lease Net Revenues Variance Account	**170**	60
Hydroelectric Water Conditions Variance Account	**119**	173
Nuclear Deferral and Variance Over/Under Recovery Variance Account	**101**	61
Other deferral and variance accounts [2]	**211**	143
	1,214	1,169
Pension and OPEB Regulatory Liability *(Note 13)*	**583**	16
Total regulatory liabilities	**1,797**	1,185
Less: current portion	**246**	246
Non-current regulatory liabilities	**1,551**	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 Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges Variance Account, 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.

During the years ended December 31, 2025 and 2024, 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, 2025 and 2024, amortization of regulatory assets and liabilities for regulatory account balances 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 2.91 to 3.64 percent per annum during the year ended December 31, 2025 (2024 – 4.40 to 5.49 percent per annum).

The December 2025 amendments to *Ontario Regulation 53/05* established a mechanism for recovery through regulated prices of interest amounts in respect of the capital expenditures on the refurbishment of Units 5 to 8 of the Pickering nuclear generating station (Pickering GS) and the capital expenditures on the DNNP prior to such assets being placed in service, effective January 1, 2026. Under the mechanism, the OEB-approved revenue requirement used to set regulated prices for OPG's existing nuclear facilities and the DNNP SMR facilities must include an amount equal to the product of the forecast cumulative capital expenditures incurred in respect of the Pickering Refurbishment project and the DNNP, respectively, other than any such amounts that have been placed in service, and OPG's cost of long-term borrowing approved by the OEB. The amendments also established variance accounts for OPG to record, as applicable and including in respect of DNNP LP, the differences between such forecast interest amounts included in the respective revenue requirements and the amounts determined by multiplying such actual cumulative capital expenditures by OPG's cost of long-term borrowing as approved by the OEB, effective January 1, 2026. The regulation requires the OEB to authorize disposition of the balances in these accounts, together with interest at OPG's cost of long-term borrowing approved by the OEB, on an annual basis in the year following the year in which the amounts are recorded in the account.

The December 2025 amendments to *Ontario Regulation 53/05* established a variance account for DNNP LP to record the revenue requirement impact of differences between the OEB-approved forecast capital and non-capital costs incurred and firm financial commitments made by DNNP LP for the DNNP and such actual amounts, as well as differences in net revenue earned by DNNP LP as a result of any difference between the OEB-approved forecast in-service date of a DNNP SMR and such actual date. The disposition of the balance recorded in the accounts is subject to the OEB's review.

The December 2025 amendments to *Ontario Regulation 53/05* authorized a variance account for DNNP LP to record, for future disposition and until the effective date of the OEB's first order setting regulated prices for the DNNP SMR facilities after the DNNP has been completed, the revenue requirement impacts of the differences between DNNP LP's actual capital structure and cost of debt, and such capital structure and cost of debt parameters approved by the OEB in setting regulated prices for the DNNP SMRs. The disposition of the balance in the account is subject to the OEB's review of the borrowing costs incurred by DNNP LP.

In December 2025, OPG filed a five-year application with the OEB for new regulated prices for electricity generated from OPG's regulated hydroelectric and nuclear facilities, including for the DNNP SMR facilities on behalf of DNNP LP, with a proposed effective date of January 1, 2027. The application reflects the December 2025 amendments to *Ontario Regulation 53/05*. For the nuclear facilities, the application proposes base regulated prices determined under a custom incentive regulation framework consistent with prior OPG applications. As required by *Ontario Regulation 53/05* with respect to any period until the effective date of the OEB's first order setting regulated prices for the DNNP SMR facilities after the DNNP has been completed, the application requests blended nuclear base regulated prices for OPG's existing

nuclear facilities and the DNNP SMR facilities, by combining the respective annual revenue requirements and production forecasts. For the regulated hydroelectric facilities, the application proposes base regulated prices determined under a custom incentive regulation framework that would rebase the base regulated price using a forecast cost-of-service approach for the 2027 year, based on the corresponding revenue requirement and production forecast, and, for the four subsequent years, escalate the price annually using a formula that includes an inflation factor based on indices published annually by the OEB, as increased by an incremental capital funding adjustment to support forecasted investment levels and as reduced by a stretch factor adjustment. The OEB has processed OPG's application and the public proceeding is underway.

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 Refurbish-ment Variance Account**	**Pickering B Variance Account**	**Hydro-electric Surplus Baseload Genera-tion Variance Account**	**Pension & OPEB Cash Versus Accrual Differen-tial Deferral Account**	**Nuclear Develop-ment Variance Account**	**Pension and OPEB Cost Variance Account**	**Pension & OPEB Cash Payment Variance Account**	**Bruce Lease Net Revenues Variance Account**	**Hydro-electric Water Condi-tions Variance Account**	**Nuclear Deferral and Variance Over/ Under Recovery Variance Account**	**Pension and OPEB Regula-tory Asset (Liability)**	**Deferred Income Taxes**	**Other Deferral and Variance (net) Accounts** [1]	**Total**
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)		
Net regulatory assets (liabilities) January 1, 2024	654	378	384	26	393	602	122	(319)	(426)	55	(185)	(77)	619	1,938	(99)	4,065
Increase (decrease)	-	180	54	102	11	(11)	(18)	(95)	(12)	(85)	(35)	(1)	(635)	213	38	(294)
Interest	23	-	22	3	17	-	4	-	(18)	(1)	(9)	(4)	-	-	(1)	36
Amortization	-	(38)	-	-	(114)	(215)	(23)	3	135	(29)	56	21	-	-	119	(85)
Net regulatory assets (liabilities) December 31, 2024	677	520	460	131	307	376	85	(411)	(321)	(60)	(173)	(61)	(16)	2,151	57	3,722
Increase (decrease)	**-**	**2**	**46**	**212**	**18**	**(6)**	**83**	**(33)**	**(18)**	**(84)**	**18**	**(61)**	**(567)**	**111**	**(94)**	**(373)**
Interest	**25**	**-**	**15**	**6**	**6**	**-**	**3**	**-**	**(7)**	**(4)**	**(4)**	**(2)**	**-**	**-**	**(2)**	**36**
Amortization	**-**	**(75)**	**(79)**	**-**	**(117)**	**(204)**	**(43)**	**49**	**128**	**(22)**	**40**	**23**	**-**	**-**	**6**	**(294)**
Net regulatory assets (liabilities) December 31, 2025	**702**	**447**	**442**	**349**	**214**	**166**	**128**	**(395)**	**(218)**	**(170)**	**(119)**	**(101)**	**(583)**	**2,262**	**(33)**	**3,091**

[1] Includes balances related to Other category.

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. Per the regulation, the Rate Smoothing Deferral Account records interest at OPG's cost of long-term borrowing approved by the OEB, compounded annually. The regulation requires the OEB to authorize the 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 OEB-approved nuclear revenue requirements would 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)	**2025**	**2024**
Fuel expense	**15**	21
Low and intermediate level waste management variable expenses [1]	**13**	26
Depreciation expense	**1**	110
Return on rate base [2]	**1**	3
Income taxes	**(28)**	20
	2	180

[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, which include costs related to the refurbishment of the Darlington nuclear generating station and the Pickering nuclear generating station, refurbishment and other life extension activities at regulated hydroelectric facilities, and other eligible projects.

d) Pickering B Variance Account

The Pickering B Variance Account (formerly 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.

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.

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) Pension & OPEB Cash Versus Accrual Differential Deferral Account

The Pension & OPEB Cash Versus Accrual Differential Deferral Account recorded, for a period prior to January 1, 2022, 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, in respect of the regulated hydroelectric facilities and the nuclear facilities. For the 2022-2026 period, the account is recording these differences for the regulated hydroelectric facilities only. 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, and therefore, for the nuclear facilities, the account only records amortization of balances approved for recovery by the OEB, effective January 1, 2022.

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.

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.

h) Pension and OPEB Cost Variance Account

The Pension and OPEB Cost Variance Account was established to record 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 OPG's regulated prices then in effect. For the 2022-2026 period, the account is recording such differences for the nuclear facilities only, 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.

i) Pension & OPEB Cash Payment Variance Account

The Pension & OPEB Cash Payment Variance Account recorded, for a period prior to January 1, 2022, the differences between OPG's actual contributions to its registered pension plan and expenditures on its OPEB and supplementary pension plans, in respect of the regulated hydroelectric facilities and the nuclear facilities, and such forecast amounts reflected in the regulated prices. For the 2022-2026 period, the account is recording these differences for the regulated hydroelectric facilities only. 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, and therefore, for the nuclear facilities, the account only records amortization of balances approved for recovery by the OEB, effective January 1, 2022.

j) Bruce Lease Net Revenues Variance Account

In accordance with *Ontario Regulation 53/05*, the OEB is required to include the difference between OPG's revenues and costs associated with the Bruce nuclear generating stations in the determination of the regulated prices for production from OPG's regulated nuclear facilities. Based on *Ontario Regulation 53/05* requirements, the OEB has established a variance account that captures differences between OPG's actual revenues and costs related to the Bruce nuclear generating stations and the corresponding forecasts included in approved nuclear regulated prices, including the costs associated with OPG's Nuclear Liabilities and the earnings from the portion of the Nuclear Segregated Funds related to the Bruce nuclear generating stations.

k) 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 the hydroelectric base regulated prices, and the actual water conditions.

l) 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.

m) Pension and OPEB Regulatory Liability

The Pension and OPEB Regulatory Liability represents 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 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 12.

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 11.

7. 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)	**2025**	**2024**
Opening balance, January 1	**230**	168
Acquisition of Lightstar Renewables LLC and Lightstar Operations One LLC	**-**	43
Foreign exchange differences	**(16)**	19
Goodwill written down [1]	**(214)**	-
Closing balance, December 31	**-**	230

[1] Further details on the transaction to sell Eagle Creek can be found in Note 23.

8. 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	2025	2024
Medium Term Note Program [1]				
Senior Notes	3.82%	2026 - 2055	**6,550**	5,950
Notes payable under OEFC and corporate credit facilities [1]				
Senior Notes	3.47%	2026 - 2048	**2,811**	2,859
UMH Energy Partnership [2]				
Senior Notes	7.59%	2041	**157**	160
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	4.90%	2028 - 2030	**-**	516
Other			**25**	25
			11,783	11,750
Less: unamortized bond issuance fees			**(44)**	(43)
Less: amounts due within one year			**(673)**	(604)
Long-term debt			**11,066**	11,103

[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. Following the agreement to sell Eagle Creek in October 2025, the carrying value of these notes was reclassified as liabilities associated with assets held for sale. The outstanding balance as at December 31, 2025 was $296 million, which was transferred to the buyer upon closing of the transaction to sell Eagle Creek on January 9, 2026. Further details on the transaction can be found in Note 23.

In March 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 year ended December 31, 2025.

In October 2025, OPG repaid USD $140 million of senior notes payable by OPG Eagle Creek Holdings LLC and its subsidiaries.

For the year ended December 31, 2025, net repayment of long-term debt under the Company's corporate credit facilities totalled $48 million (2024 – net issuance of $37 million), which comprised repayment of $220 million (2024 – repayment of $400 million) and issuances of $172 million (2024 – issuances of $437 million).

Net Interest Expense

Net interest expense for the years ended December 31 was as follows:

(millions of dollars)	**2025**	**2024**
Interest on long-term debt	**468**	401
Interest on short-term debt	**17**	24
Interest income	**(83)**	(88)
Interest capitalized to property, plant and equipment and intangible assets	**(181)**	(136)
Interest related to regulatory assets and regulatory liabilities [1]	**(27)**	(15)
Net interest expense	**194**	186

[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 2025 was $485 million (2024 – $442 million), of which $468 million (2024 – $418 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), Lower Mattagami Energy Limited Partnership (LME) and Lower Mattagami Limited Partnership (LMLP) against their debt as at December 31, 2025 was $4,191 million (2024 – $5,013 million).

9. SHORT-TERM DEBT

Committed credit facilities and maturity dates as at December 31, 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 [4]
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 December 31, 2025.
[4] Subsequent to December 31, 2025, the facility was transferred to the buyer following the closing of the transaction to sell Eagle Creek on January 9, 2026. Further details on the transaction can be found in Note 23.

Short-term debt as at December 31 was as follows:

(millions of dollars)	**2025**	**2024**
Lower Mattagami Energy Limited Partnership	**170**	215
Corporate commercial paper	**503**	-
Total short-term debt	**673**	215

As at December 31, 2025, a total of $799 million of letters of credit had been issued (2024 – $504 million). As at December 31, 2025, this included $345 million for the supplementary pension plans, $270 million for general corporate purposes, $76 million for Atura Power, $65 million for LME, $15 million for OPG Eagle Creek Holdings LLC and its subsidiaries, $14 million for UMH, $10 million for Laurentis Energy Partners and its subsidiaries, $3 million for PowerON Energy Solutions LP and $1 million for PSS.

The weighted average interest rate on the short-term debt as of December 31, 2025 is 2.58 percent (2024 – 3.71 percent).

10. 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)	**2025**	**2024**
Liability for used nuclear fuel management	**16,542**	15,991
Liability for nuclear decommissioning and nuclear low and intermediate level waste management	**9,853**	9,782
Liability for non-nuclear fixed asset removal	**270**	269
Fixed asset removal and nuclear waste management liabilities	**26,665**	26,042

The changes in the fixed asset removal and nuclear waste management liabilities for the years ended December 31 were as follows:

(millions of dollars)	**2025**	**2024**
Liabilities, beginning of year	**26,042**	25,386
Increase in liabilities due to accretion [1]	**1,214**	1,203
Decrease in liabilities reflecting changes in the estimate of liabilities for thermal generating facilities and other adjustments	**(12)**	(10)
Increase in liabilities due to used nuclear fuel, nuclear waste management and other expenses [1]	**142**	163
Liabilities settled by expenditures on fixed asset removal and nuclear waste management during the year [2]	**(721)**	(700)
Liabilities, end of year	**26,665**	26,042

[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. The nuclear

liabilities were further updated as of December 31, 2023 to reflect the extension of the accounting end-of-life assumptions for Units 5 to 8 of the Pickering GS.

For the purposes of calculating the Nuclear Liabilities as at December 31, 2025, 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. The cost estimates associated with the APM plan are updated based on information provided by the NWMO. With programs of such long-term duration, the multiple assumptions involved 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, based on technical and financial information developed by the NWMO.

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 include a conceptual long-term disposal strategy assumption 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 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 evaluates underlying assumptions and estimates based on available information.

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 in the Nuclear Segregated 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 Canadian Nuclear Safety Commission (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, 2025 and 2024, 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, 2025 and 2024 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 $25.3 billion in present value dollars as at December 31, 2025. 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, 2025 and 2024, after taking into account the committed return adjustment. The due to the Province amount recognized for the fund as at December 31, 2025 and 2024 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 2025	2024
Decommissioning Segregated Fund	**15,145**	14,220
Due to Province – Decommissioning Segregated Fund	**(5,356)**	(4,545)
	9,789	9,675
Used Fuel Segregated Fund [1]	**19,782**	18,428
Due to Province – Used Fuel Segregated Fund	**(6,754)**	(5,691)
	13,028	12,737
Total Nuclear Segregated Funds	**22,817**	22,412
Less: current portion	**(145)**	(283)
Non-current Nuclear Segregated Funds	**22,672**	22,129

[1] The NFWA Trust represents $5,511 million as at December 31, 2025 (2024 – $5,211 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)	**2025**	**2024**
Cash and cash equivalents and short-term investments	**385**	444
Alternative investments	**9,439**	8,424
Pooled funds	**3,591**	3,447
Marketable equity securities	**12,038**	11,926
Fixed income securities	**9,389**	8,352
Net receivables/payables	**85**	55
	34,927	32,648
Less: Due to Province	**(12,110)**	(10,236)
	22,817	22,412

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:

	2025		
(millions of dollars)	**Decommissioning Segregated Fund**	**Used Fuel Segregated Fund**	**Total**
Historical cost	**12,157**	**15,967**	**28,124**
Gross unrealized gains (losses)			
Aggregate appreciation	**3,289**	**4,051**	**7,340**
Aggregate depreciation	**(567)**	**(699)**	**(1,266)**
Foreign exchange	**266**	**463**	**729**
	15,145	**19,782**	**34,927**
Less: Due to Province	**(5,356)**	**(6,754)**	**(12,110)**
Total fair value	**9,789**	**13,028**	**22,817**
Less: current portion	**(95)**	**(50)**	**(145)**
Non-current fair value	**9,694**	**12,978**	**22,672**

	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

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)	2025 Decommissioning Segregated Fund	2025 Used Fuel Segregated Fund	2025 Total
Net realized gains			
Net realized gains excluding foreign exchange	**801**	**1,045**	**1,846**
Net realized foreign exchange gains	**72**	**99**	**171**
Net realized gains	**873**	**1,144**	**2,017**
Net unrealized gains			
Net unrealized gains excluding foreign exchange	**478**	**514**	**992**
Net unrealized foreign exchange losses	**(318)**	**(299)**	**(617)**
Net unrealized gains	**160**	**215**	**375**

(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

The change in the Nuclear Segregated Funds for the years ended December 31 was as follows:

(millions of dollars)	Fair Value 2025	Fair Value 2024
Decommissioning Segregated Fund, beginning of year	**9,675**	9,305
Increase in fund due to return on investments	**1,296**	1,612
Decrease in fund due to reimbursement of eligible expenditures	**(371)**	(105)
Increase in due to Province	**(811)**	(1,137)
Decommissioning Segregated Fund, end of year	**9,789**	9,675
Used Fuel Segregated Fund, beginning of year	**12,737**	12,258
Increase in fund due to return on investments	**1,704**	2,085
Decrease in fund due to reimbursement of eligible expenditures	**(350)**	(147)
Increase in due to Province	**(1,063)**	(1,459)
Used Fuel Segregated Fund, end of year	**13,028**	12,737

The earnings from the Nuclear Segregated Funds during the years ended December 31, 2025 and 2024 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)	**2025**	**2024**
Decommissioning Segregated Fund	**485**	475
Used Fuel Segregated Fund	**641**	626
Bruce Lease Net Revenues Variance Account	**12**	1
Earnings on nuclear fixed asset removal and nuclear waste management funds	**1,138**	1,102

11. 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)	**2025**		**2024**	
Income before income taxes	**1,981**		1,176	
Canadian federal statutory income tax rate applied to accounting income	**495**	**25.0%**	294	25.0%
Increase (decrease) in income taxes resulting from:				
Loss on assets held for sale	**107**	**5.4%**	-	0%
Canadian provincial income tax	**228**	**11.5%**	135	11.5%
Federal abatement	**(198)**	**(10.0)%**	(118)	(10.0)%
Income tax expense deferred in regulatory assets and regulatory liabilities	**(78)**	**(3.9)%**	(125)	(10.6)%
Scientific Research and Experimental Development investment tax credits	**(24)**	**(1.2)%**	(22)	(1.9)%
Manufacturing and processing credit	**(36)**	**(1.8)%**	(18)	(1.5)%
Change in unrecognized tax benefits	**(35)**	**(1.8)%**	(8)	(0.7)%
Foreign tax effects - valuation allowance	**5**	**0.3%**	15	1.2%
Other	**(11)**	**(0.6)%**	17	1.5%
	(42)	**(2.1)%**	(124)	(10.5)%
Income tax expense and effective rate of income taxes	**453**	**22.9%**	170	14.5%

Significant components of the income tax expense for the years ended December 31 were as follows:

(millions of dollars)	**2025**	**2024**
Current income tax expense	**440**	131
Deferred income tax expense	**13**	39
Income tax expense	**453**	170

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)	**2025**	**2024**
Deferred income tax assets:		
Fixed asset removal and nuclear waste management liabilities	**6,663**	6,512
Other assets and liabilities	**1,326**	1,486
Valuation allowance	**-**	(77)
	7,989	7,921
Deferred income tax liabilities:		
Property, plant and equipment and intangible assets	**(2,782)**	(2,747)
Nuclear fixed asset removal and nuclear waste management funds	**(5,704)**	(5,603)
Other assets and liabilities	**(2,024)**	(2,032)
	(10,510)	(10,382)
Net deferred income tax liabilities	**(2,521)**	(2,461)

During 2025, 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 $111 million (2024 – $213 million) and a corresponding increase to the regulatory asset for deferred income taxes. As a result, the deferred income tax expense for 2025 and 2024 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)	**2025**	**2024**
January 1:		
Deferred income tax liabilities on temporary differences related to regulated operations	**1,613**	1,453
Deferred income tax liabilities on temporary differences related to the regulatory asset for deferred income tax liabilities	**538**	485
	2,151	1,938
Changes during the year:		
Increase in deferred income tax liabilities on temporary differences related to regulated operations	**83**	160
Increase in deferred income tax liabilities on temporary differences related to the regulatory asset for deferred income tax liabilities	**28**	53
Balance as at December 31	**2,262**	2,151

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 is as follows:

(millions of dollars)	**2025**	**2024**
Unrecognized tax benefits, beginning of year	**75**	84
Additions	**10**	7
Reductions	**(44)**	(16)
Unrecognized tax benefits, end of year	**41**	75

As at December 31, 2025, OPG's unrecognized tax benefits were $41 million (2024 – $75 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, 2025, OPG had recorded interest on unrecognized tax benefits of $8 million (2024 – $20 million). OPG and certain of its subsidiaries are subject to taxation in Canada and certain foreign jurisdictions. As of December 31, 2025, OPG remained subject to income tax examination for years after 2020 in Canada, while certain of its wholly owned US subsidiaries were subject to federal and state income tax examinations for tax years after 2019 and 2018, respectively.

OPG received $65 million in tax refunds related to payments in lieu of income taxes during 2025 (2024 – $216 million paid in payments in lieu of income taxes). OPG paid a negligible amount in Canadian federal and provincial income taxes, US federal and state income taxes and income taxes in other foreign jurisdictions in 2025 and 2024.

12. 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:

	2025			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges**	**Pension and OPEB**	**Currency Translation Adjustment**	**Total**
Balance, beginning of year	**5**	**6**	**182**	**193**
Net gain on cash flow hedges	**1**	**-**	**-**	**1**
Actuarial gain on remeasurement of liabilities and past service costs for pension and OPEB	**-**	**36**	**-**	**36**
Amounts reclassified from AOCI	**3**	**(2)**	**-**	**1**
Translation of foreign operations	**-**	**-**	**(101)**	**(101)**
Other comprehensive income (loss) for the year	**4**	**34**	**(101)**	**(63)**
Balance, end of year	**9**	**40**	**81**	**130**

	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

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)	**2025**	**2024**	**Statement of Income Line Item**
Amortization of amounts related to cash flow hedges			
Losses (gains)	**4**	(7)	Revenue and Net interest expense
Income tax (expense) recovery	**(1)**	2	Income tax expense
	3	(5)	
Amortization of amounts related to pension and OPEB			
Net actuarial gains, net of past service costs	**(2)**	(2)	See (1) below
	(2)	(2)	
Total reclassifications for the year	**1**	(7)	

[1] These AOCI components are included in the computation of pension and OPEB costs (see Note 13 for additional details).

13. 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, 2025. 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 15 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:

	2025			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and cash equivalents	**412**	**-**	**-**	**412**
Short-term investments	**1**	**-**	**-**	**1**
Fixed income				
Corporate debt securities	**17**	**3,116**	**-**	**3,133**
Government bonds	**40**	**2,032**	**-**	**2,072**
Equities				
Canadian	**748**	**905**	**-**	**1,653**
US	**1,298**	**-**	**-**	**1,298**
Global	**620**	**-**	**-**	**620**
Pooled funds	**101**	**1,593**	**-**	**1,694**
Forward foreign exchange contracts	**-**	**65**	**-**	**65**
Other	**-**	**-**	**14**	**14**
	3,237	**7,711**	**14**	**10,962**
Futures contracts and repurchase agreements	**-**	**(981)**	**-**	**(981)**
	3,237	**6,730**	**14**	**9,981**
Investments measured at NAV [1]				**8,494**
				18,475 [2]

	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]

[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	
	2025	**2024**	**2025**	**2024**
Weighted average assumptions – benefit obligations at year-end				
Discount rate for projected benefit obligation	**4.98 %**	4.70 %	**4.99 %**	4.70 %
Salary schedule escalation rate - initial rate [1]	**2.68 %**	3.00 %	**2.67 %**	3.00 %
- thereafter	**2.75 %**	2.75 %	**2.74 %**	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	**5.02 %**	5.40 %
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	
	2025	**2024**	**2025**	**2024**
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	**4.80 %**	4.62 %	**4.64 %**	4.61 %
Discount rate for interest on projected benefit obligation	**4.39 %**	4.63 %	**4.43 %**	4.63 %
Discount rate for interest on current service cost	**4.71 %**	4.63 %	**4.48 %**	4.63 %
Salary schedule escalation rate - initial rate [2]	**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	**5.44 %**	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 %
Expected average remaining service life for employees (years)	**15**	14	**15**	15

n/a – assumption not applicable.
[1] Average rate per year to December 31, 2028 for 2025 and December 31, 2026 for 2024.
[2] Average rate per year to December 31, 2026.

(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 year						
Current service costs	**297**	305	**10**	8	**104**	99
Interest on projected benefit obligation	**767**	791	**18**	17	**128**	130
Expected return on plan assets, net of expenses	**(1,074)**	(1,031)	**-**	-	**-**	-
Amortization of past service (credits) costs [1]	**-**	(1)	**-**	-	**5**	2
Amortization of net actuarial (gain) loss [1]	**(1)**	-	**3**	4	**(28)**	(29)
Recognition of LTD past service costs	**-**	-	**-**	-	**-**	1
Recognition of LTD net actuarial loss (gain)	**-**	-	**-**	-	**32**	(26)
Costs recognized [2]	**(11)**	64	**31**	29	**241**	177

[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 6.

[2] Excludes the impact of regulatory accounts discussed in Note 6.

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)	2025	2024
Registered pension plans	**(11)**	64
Supplementary pension plans	**31**	29
Other post-employment benefits	**241**	177
Pension and OPEB Cost Variance Account	**29**	68
Pension & OPEB Cash Payment Variance Account	**18**	12
Pension & OPEB Cash Versus Accrual Differential Deferral Account	**6**	11
Pension and other post-employment benefit costs	**314**	361

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)	**2025**	**2024**	**2025**	**2024**	**2025**	**2024**
Change in plan assets						
Fair value of plan assets, beginning of year	**17,806**	16,636	**-**	-	**-**	-
Contributions by employer	**149**	206	**19**	17	**130**	119
Contributions by employees	**134**	121	**-**	-	**-**	-
Actual return on plan assets, net of expenses	**1,283**	1,668	**-**	-	**-**	-
Benefit payments	**(866)**	(825)	**(19)**	(17)	**(130)**	(119)
Fair value of plan assets, end of year	**18,506**	17,806	**-**	-	**-**	-
Change in projected benefit obligations						
Projected benefit obligations, beginning of year	**17,469**	17,158	**400**	378	**2,848**	2,770
Employer current service costs	**297**	305	**10**	8	**104**	99
Contributions by employees	**134**	121	**-**	-	**-**	-
Interest on projected benefit obligation	**767**	791	**18**	17	**128**	130
Benefit payments	**(866)**	(825)	**(19)**	(17)	**(130)**	(119)
Past service costs	**-**	15	**-**	-	**5**	24
Net actuarial (gain) loss	**(391)**	(96)	**(9)**	14	**5**	(56)
Projected benefit obligations, end of year	**17,410**	17,469	**400**	400	**2,960**	2,848
Funded status – surplus (deficit), end of year	**1,096**	337	**(400)**	(400)	**(2,960)**	(2,848)

The pension and OPEB assets (liabilities) composition as at December 31 was as follows:

	Registered Pension Plans		Supplementary Pension Plans		Other Post-Employment Benefits	
(millions of dollars)	**2025**	**2024**	**2025**	**2024**	**2025**	**2024**
Non-current assets	**1,096**	337	**-**	-	**-**	-
Current liabilities	**-**	-	**(19)**	(17)	**(145)**	(132)
Non-current liabilities	**-**	-	**(381)**	(383)	**(2,815)**	(2,716)
Total assets (liabilities)	**1,096**	337	**(400)**	(400)	**(2,960)**	(2,848)

The accumulated benefit obligations for the registered pension plans and supplementary pension plans as at December 31, 2025 were $15,944 million and $342 million, respectively (2024 – $15,966 million and $341 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 decreased from $17,469 million as at December 31, 2024 to $17,410 million as at December 31, 2025. The decrease was mainly due to a remeasurement of the benefit obligations at the end of 2025 reflecting higher discount rates. The projected benefit obligations for the supplementary pension plan were $400 million as at December 31, 2025 and 2024.

The projected benefit obligations for OPEB plans increased from $2,848 million as at December 31, 2024 to $2,960 million as at December 31, 2025. This increase was largely due to the interest costs on the liabilities during 2025 and the impact of the updated, higher per capita health care claims costs assumption as part of the 2025 actuarial valuation, partially offset by the remeasurement of the benefit obligations reflecting an increase in the discount rates at the end of 2025.

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 6, for the years ended December 31, on a pre-tax basis:

	Registered Pension Plans		Supplementary Pension Plans		Other Post-Employment Benefits	
(millions of dollars)	**2025**	**2024**	**2025**	**2024**	**2025**	**2024**
Changes in plan assets and benefit obligations recognized in OCI						
Current year net actuarial (gain) loss	**(600)**	(733)	**(9)**	14	**(27)**	(30)
Current year past service costs	**-**	15	**-**	-	**5**	23
Amortization of net actuarial gain (loss)	**1**	-	**(3)**	(4)	**28**	29
Amortization of past service credits (costs)	**-**	1	**-**	-	**(5)**	(2)
Total (increase) decrease in OCI	**(599)**	(717)	**(12)**	10	**1**	20
Less: (decrease) increase in Pension and OPEB Regulatory Asset *(Note 6)*	**(553)**	(664)	**(11)**	9	**(3)**	20
Net (increase) decrease in OCI (pre-tax)	**(46)**	(53)	**(1)**	1	**4**	-

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)	**2025**	**2024**	**2025**	**2024**	**2025**	**2024**
Unamortized amounts recognized in AOCI						
Past service costs	**11**	11	**-**	-	**52**	52
Net actuarial (gain) loss	**(95)**	504	**85**	97	**(686)**	(687)
Total recognized in AOCI	**(84)**	515	**85**	97	**(634)**	(635)
Less: Pension and OPEB Regulatory (Liability) Asset *(Note 6)*	**(80)**	473	**79**	90	**(582)**	(579)
Net recognized in AOCI (pre-tax)	**(4)**	42	**6**	7	**(52)**	(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)	**2025**	**2024**	**2025**	**2024**	**2025**	**2024**
Net actuarial gain not yet subject to amortization due to use of market-related values	**(831)**	(340)	**-**	-	**-**	-
Net actuarial loss (gain) not subject to amortization due to use of the corridor	**755**	853	**40**	40	**(266)**	(259)
Net actuarial (gain) loss subject to amortization	**(19)**	(9)	**45**	57	**(420)**	(428)
Unamortized net actuarial (gain) loss	**(95)**	504	**85**	97	**(686)**	(687)
Unamortized past service costs	**11**	11	**-**	-	**52**	52

The most recently filed actuarial valuation, for funding purposes, of the OPG registered pension plan, as at January 1, 2025, was filed with the Financial Services Regulatory Authority of Ontario in September 2025. The next filed funding valuation must have an effective date no later than January 1, 2028. For 2026, the Company's estimated contribution to the OPG registered pension plan is expected to be $131 million.

As part of the actuarial valuation for funding purposes of the registered pension plan as at January 1, 2025, the plan's demographic and other assumptions were reviewed and revised, as necessary, by independent actuaries. Using updated demographic data as at January 1, 2025, 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 2025. The results of this valuation were reflected in the 2025 year-end obligations reflecting appropriate assumptions for accounting purposes as at December 31, 2025.

The supplementary pension plans are not funded, but are secured by letters of credit totalling $345 million as at December 31, 2025 (2024 – $314 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, 2025 were as follows:

(millions of dollars)	**Registered Pension Plans**	**Supplementary Pension Plans**	**Other Post-Employment Benefits**
2026	906	19	145
2027	915	19	147
2028	963	19	147
2029	964	20	149
2030	983	20	151
2031 through 2035	5,321	108	817

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, 2025 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	**(43)**	**n/a**	**n/a**
0.25% decrease	**43**	**n/a**	**n/a**
Discount rate			
0.25% increase	**(12)**	**(1)**	**(11)**
0.25% decrease	**13**	**1**	**11**
Inflation [2]			
0.25% increase	**59**	**1**	**1**
0.25% decrease	**(54)**	**(1)**	**(1)**
Salary increases			
0.25% increase	**15**	**5**	**1**
0.25% decrease	**(16)**	**(4)**	**(1)**
Health care cost trend rate			
1% increase	**n/a**	**n/a**	**64**
1% decrease	**n/a**	**n/a**	**(49)**

n/a – change in assumption not applicable.
[1] Excludes the impact of regulatory accounts.
[2] With a corresponding change in the salary increase assumption.

14. 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. This risk was reduced subsequent to December 31, 2025, upon the completion of the sale of Eagle Creek on January 9, 2026.

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.

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, 2025 was $1 million (2024 − less than $1 million).

The fair value of the derivative instruments totalled a net liability of $14 million as at December 31, 2025 (2024 – net liability of $17 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)	**2025**	**2024**
Cash flow hedges (recorded in AOCI)		
Reclassification of losses (gains) to revenue and net interest expense	**4**	(7)
Commodity derivatives (recorded in net income)		
Realized losses in revenue	**(2)**	(4)
Unrealized losses in revenue	**(4)**	(2)

Existing pre-tax net losses of nil deferred in AOCI as at December 31, 2025 are expected to be reclassified to net income within the next 12 months.

15. 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 is 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]	**22,817**	22,412	**22,817**	22,412	Nuclear fixed asset removal and nuclear waste management funds
Loan receivable − from Fair Hydro Trust	**829**	828	**899**	902	Loan receivable from related party
Investment in Hydro One Limited Shares	**170**	159	**170**	159	Equity securities
Long-term debt (includes current portion)	**(11,064)**	(11,204)	**(11,739)**	(11,707)	Long-term debt
Other financial instruments, net	**165**	129	**165**	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 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:

	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	**7,083**	**7,400**	**-**	**14,483**
Investments measured at NAV [1]				**5,299**
				19,782
Due to Province				**(6,754)**
Used Fuel Segregated Fund, net				**13,028**
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**5,352**	**5,653**	**-**	**11,005**
Investments measured at NAV [1]				**4,140**
				15,145
Due to Province				**(5,356)**
Decommissioning Segregated Fund, net				**9,789**
Equity securities	**170**	**-**	**-**	**170**
Other financial assets	**23**	**11**	**181**	**215**
Liabilities				
Other financial liabilities	**(50)**	**-**	**-**	**(50)**

	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 consolidated balance sheets.

For the year ended December 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 year ended December 31, 2025 were as follows:

(millions of dollars)	**Other financial instruments**
Opening balance, January 1, 2025	**97**
Realized losses included in revenue	**(2)**
Unrealized gains included in revenue	**75**
Purchases	**11**
Closing balance, December 31, 2025	**181**

Investments Measured at Net Asset Value

Nuclear Segregated Funds

The 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, 2025 were as follows:

(millions of dollars except where noted)	**Fair Value**	**Unfunded Commitments**	**Redemption Frequency**	**Redemption Notice**
Real assets				
Infrastructure	**4,933**	**1,513**	**n/a**	**n/a**
Real estate	**3,541**	**1,228**	**n/a**	**n/a**
Private debt	**552**	**656**	**n/a**	**n/a**
Other	**413**	**16**	**n/a**	**n/a**
Pooled funds				
Fixed income	**2,418**	**n/a**	**Daily**	**1-5 days**
Equity	**1,173**	**n/a**	**Daily**	**1-5 days**
Total	**13,030**	**3,413**		

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 is 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.

16. SHARE CAPITAL

Common Shares

As at December 31, 2025 and 2024, 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. OPG is entitled to redeem outstanding Class A shares as may be approved by OPG's Board of Directors.

As at December 31, 2025 and 2024, OPG had 18,343,815 Class A shares issued and outstanding at a stated value of $787 million.

Class B Preferred Shares

The Company's Articles of Amalgamation were further amended effective November 26, 2025 to allow for the creation and issuance of Class B non-voting preferred shares, issuable in one or more series, to the Province. Each series of Class B preferred shares ranks on parity with every other series of Class B preferred shares, and is entitled to a preference over the common shares and the Class A shares, with respect to dividends and the return of capital in the event of the liquidation, dissolution or winding up of OPG.

In December 2025, OPG issued 1,000,000 Class B preferred shares, series 1 (Series 1 Preferred Shares) at a price of $1,000 per share to the Province for its equity injection in OPG, generating proceeds of $1,000 million.

The holders of the Series 1 Preferred Shares are entitled to receive fixed cumulative preferential PIK dividends of $50 per share per year as and when declared by the Board of Directors, payable semi-annually by either, at the option of OPG, increasing the liquidation preference and redemption price per share by the PIK dividend amount, or issuing additional Series 1 Preferred Shares equal to the PIK dividend amount divided by $1,000. The Series 1 Preferred Shares will be redeemable by OPG after December 15, 2035, subject to certain conditions, at a redemption price equal to $1,000 per share, plus any paid dividends or accrued and unpaid PIK dividends.

As at December 31, 2025, OPG had 1,000,000 Series 1 Preferred Shares issued and outstanding at a stated value of $1,002 million (2024 – nil). Accrued and unpaid PIK dividends as at December 31, 2025, were $2 million (2024 – nil).

Any issue of a new shares is subject to the consent of the Province.

17. EARNINGS PER COMMON SHARE

Basic and diluted earnings per share are calculated by dividing net income attributable to the Shareholder, net of PIK dividends, by the weighted average number of common shares outstanding.

Class A shares are included in the weighted average number of common shares outstanding. The weighted average number of common shares outstanding as at December 31, 2025 and 2024 was 274.6 million. There were no dilutive securities during the years ended December 31, 2025 and 2024.

18. 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, individually and in the aggregate, is not likely to have a material adverse impact on its consolidated financial position.

Guarantees and Indemnifications

Periodically, OPG and its subsidiaries may enter into various agreements to provide financial or performance assurance to third parties. Such agreements include guarantees, indemnifications, standby Letters of Credit and surety bonds.

The Company has entered into certain guarantees and indemnifications, which in aggregate have a maximum potential of future payments totalling $454 million (2024 - $30 million). As at December 31, 2025, in relation to the events covered by these agreements, the Company had recognized $69 million (2024 – nil) in liabilities on the consolidated balance sheets. As current estimates change, additional losses related to guarantees, indemnifications, standby Letters of Credit and surety bonds to third parties, which could be material, may be recorded by the Company in the future.

Contractual Obligations

OPG's contractual obligations as at December 31, 2025 were as follows:

(millions of dollars)	2026	2027	2028	2029	2030	Thereafter	Total
Fuel supply agreements	237	273	199	250	273	1,501	2,733
Contributions to the OPG registered pension plan [1]	131	134	-	-	-	-	265
Long-term debt repayment	674	530	5	505	805	9,264	11,783
Interest on long-term debt	453	443	425	425	397	5,520	7,663
Commitments related to Darlington Refurbishment project [2]	65	-	-	-	-	-	65
Commitments related to Atura Power development projects [2]	205	19	8	1	-	-	233
Commitments related to Pickering Refurbishment project [2]	527	-	-	-	-	-	527
Commitments related to Darlington New Nuclear Project [2]	367	-	-	-	-	-	367
Operating licences	61	63	61	62	59	120	426
Operating lease obligations	22	18	13	13	9	42	117
Other	54	49	44	33	21	360	561
Total	2,796	1,529	755	1,289	1,564	16,807	24,740

[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, 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.

[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*, 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 December 2025 amendments to *Ontario Regulation 53/05* confirmed that the OEB is required to ensure that OPG recovers all the costs it incurs in relation to its nuclear waste management and nuclear decommissioning obligations associated with the Bruce nuclear generating station as they are reflected in OPG's audited consolidated financial statements.

The net book value of PP&E on lease to Bruce Power as at December 31, 2025 was $1,588 million (2024 – $1,633 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, 2025, the PWU represented approximately 5,100 regular and term-based employees, or 45 percent of OPG and its subsidiaries' regular workforce. Union membership includes station operators, technicians, skilled trades, clerical staff and security personnel.

As at December 31, 2025, the Society represented approximately 4,300 regular and term-based employees, or 38 percent of OPG and its subsidiaries' regular workforce. Union membership includes supervisors, professional engineers, scientists and other professionals. Following the expiry of the governing collective agreement on December 31, 2025, the Society and OPG received the final arbitration award for a three-year collective agreement on January 26, 2026, covering the period from January 1, 2026 to December 31, 2028.

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.

19. BUSINESS SEGMENTS

As at December 31, 2025, 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 associated 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 project expenditures for the DNNP and the operating results of DNNP LP.

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. In Ontario, the current contracts for the thermal generating facilities are set to expire in 2029 and 2034, for the solar facility in 2039 and for the hydroelectric facilities over the 2059 to 2067 period.

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.

Effective January 9, 2026, upon the sale of Eagle Creek, the Company no longer has electricity generation operations or facilities in the United States. The Contracted Hydroelectric and Other Generation business segment comprises only contracted generating facilities in Ontario from that date.

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.

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)	**2025**	**2024**
Regulated – Nuclear Generation	**85**	77
Regulated – Hydroelectric Generation	**19**	16
Contracted Hydroelectric and Other Generation	**8**	7
	112	100

Segment Income (Loss) For the Year Ended December 31, 2025 *(millions of dollars)*	Regulated			Unregulated				
	Nuclear Generation	Nuclear Sustainability Services	Hydroelectric Generation	Contracted Hydroelectric and Other Generation	Atura Power	Other	Elimination	Total
Revenue	4,499	-	1,621	929	1,143	24	-	8,216
Leasing revenue	28	-	-	-	-	5	-	33
Other revenue	-	153	-	(7)	-	213	(253)	106
Total revenue	4,527	153	1,621	922	1,143	242	(253)	8,355
Fuel expense	343	-	347	112	619	-	-	1,421
Gross margin	4,184	153	1,274	810	524	242	(253)	6,934
Operations, maintenance and administration expenses	1,962	153	412	288	113	141	(253)	2,816
Depreciation and amortization expenses	782	-	267	148	135	81	-	1,413
Accretion on fixed asset removal and nuclear waste management liabilities	-	1,232	-	9	2	-	-	1,243
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(1,138)	-	-	-	-	-	(1,138)
Property taxes	27	-	1	18	2	1	-	49
Other losses (gains) [1, 2]	14	-	20	457	2	(117)	-	376
Income (loss) before interest and income taxes	1,399	(94)	574	(110)	270	136	-	2,175
Net interest expense [2]								194
Income before income taxes								1,981
Income tax expense								453
Net income								1,528

[1] Contracted Hydroelectric and Other Generation – a pre-tax loss of $477 million was recognized in the fourth quarter of 2025 related to the sale of Eagle Creek.
[2] Other – Amounts primarily relate to fair value remeasurement of equity securities and other investments.
[3] Further details on net interest expense can be found in Note 8.

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	-	186	(263)	120
Total revenue	3,798	185	1,571	815	871	210	(263)	7,187
Fuel expense	288	-	335	59	367	-	-	1,049
Gross margin	3,510	185	1,236	756	504	210	(263)	6,138
Operations, maintenance and administration expenses	2,469	185	416	307	98	106	(263)	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 taxes	342	(108)	581	242	276	29	-	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 totalling $25 million was recognized in Regulated – Nuclear Generation, Regulated – Hydroelectric Generation and Other in connection with the OEB's decision and order during the second quarter of 2024 approving a settlement proposal on OPG's December 2023 application requesting disposition of regulatory account balances.

[2] Further details on net interest expense can be found in Note 8.

Selected Consolidated Balance Sheets Information as at December 31, 2025 *(millions of dollars)*	**Regulated**			**Unregulated**			
	Nuclear Generation	**Nuclear Sustainability Services**	**Hydroelectric Generation**	**Contracted Hydroelectric and Other Generation [1]**	**Atura Power**	**Other**	**Total**
Segment property, plant and equipment in-service, net	**13,937**	**-**	**8,386**	**4,210**	**3,191**	**468**	**30,192**
Segment construction in progress	**6,445**	**-**	**757**	**57**	**989**	**240**	**8,488**
Segment property, plant and equipment, net	**20,382**	**-**	**9,143**	**4,267**	**4,180**	**708**	**38,680**
Segment intangible assets in-service, net	**54**	**-**	**2**	**4**	**88**	**152**	**300**
Segment development in progress	**8**	**-**	**1**	**-**	**-**	**42**	**51**
Segment intangible assets, net	**62**	**-**	**3**	**4**	**88**	**194**	**351**
Segment fuel inventory	**258**	**-**	**-**	**37**	**35**	**-**	**330**
Segment materials and supplies							
Current	**142**	**-**	**-**	**3**	**-**	**-**	**145**
Long-term	**383**	**-**	**-**	**2**	**-**	**-**	**385**
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	**-**	**22,817**	**-**	**-**	**-**	**-**	**22,817**
Loan receivable from related party	**-**	**-**	**-**	**-**	**-**	**899**	**899**
Fixed asset removal and nuclear waste management liabilities	**-**	**(26,395)**	**-**	**(161)**	**(56)**	**(53)**	**(26,665)**

[1] The Contracted Hydroelectric and Other Generation segment excludes assets held for sale and liabilities associated with assets held for sale as a result of the classification of Eagle Creek as held for sale in the fourth quarter of 2025.

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							
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 from related party	-	-	-	-	-	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**	**Hydroelectri Generation**	**Contracted Hydroelectric and Other Generation**	**Atura Power**	**Other**	**Total**
Year ended December 31, 2025							
Investment in property, plant and equipment and intangible assets	**3,781**	**-**	**755**	**150**	**850**	**324**	**5,860**
Net change in accruals and other non-cash items							**(309)**
Investment in property, plant and equipment and intangible assets – cash flow							**5,551**
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

20. 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:

	2025		2024	
(millions of dollars)	**Income**	**Expense**	**Income**	**Expense**
Hydro One				
Electricity sales	**24**	**-**	18	-
Services	**-**	**12**	-	9
Dividends	**4**	**-**	5	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**811**	-	1,137
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**1,063**	-	1,459
Hydroelectric gross revenue charge	**-**	**117**	-	118
OEFC				
Hydroelectric gross revenue charge	**-**	**219**	-	223
Interest expense on long-term notes	**-**	**87**	-	88
Income taxes	**-**	**548**	-	377
Property taxes	**-**	**14**	-	13
IESO				
Electricity related revenue	**7,698**	**-**	6,473	-
Fair Hydro Trust				
Interest income	**33**	**-**	33	-
	7,759	**2,871**	6,529	3,424

[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, 2025 and 2024, the Nuclear Segregated Funds were reported net of amounts due to the Province of $12,110 million and $10,236 million, respectively.

Balances between OPG and its related parties as at December 31 were as follows:

(millions of dollars)	**2025**	**2024**
Receivables from related parties		
Hydro One	**3**	3
IESO − Electricity related receivables	**621**	608
Fair Hydro Trust	**4**	4
Province of Ontario	**-**	1
Loan receivable		
Fair Hydro Trust	**899**	902
Accounts payable, accrued charges and other payables		
Hydro One	**1**	3
OEFC	**91**	85
Province of Ontario	**7**	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 December 31, 2025, the Nuclear Segregated Funds held $1,764 million of Province of Ontario bonds (2024 – $1,740 million) and $5 million of Province of Ontario treasury bills (2024 – $8 million). As of December 31, 2025, the OPG registered pension plan held $302 million of Province of Ontario bonds (2024 − $327 million) and $2 million of Province of Ontario treasury bills (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.

In addition, as at December 31, 2025, OPG held shares in Hydro One with a fair value of $170 million (2024 – fair value of $159 million).

21. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

Years Ended December 31 *(millions of dollars)*	**2025**	**2024**
Receivables from related parties	**(12)**	15
Fuel inventory	**(25)**	3
Materials and supplies	**6**	(34)
Prepaid expenses	**11**	5
Other current assets	**(35)**	(32)
Accounts payable, accrued charges and other payables	**599**	(18)
Net changes in non-cash working capital balances	**544**	(61)

22. 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 Nanticoke 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.

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 (BESS) 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.

23. ASSETS HELD FOR SALE

In October 2025, OPG entered into an agreement to sell Eagle Creek. Subsequent to December 31, 2025, on January 9, 2026, OPG completed the sale of Eagle Creek for consideration of USD $1.48 billion (C$2.05 billion) inclusive of debt to be assumed by the buyer and other closing adjustments.

The assets and liabilities of Eagle Creek were classified as held for sale in the fourth quarter of 2025.

Eagle Creek's held for sale assets include a pre-tax loss of $477 million. The loss was recorded to write down the carrying amounts of goodwill and intangible assets as of December 31, 2025. No adjustments were made to the historical activity within the consolidated statements of income, consolidated statements of comprehensive income, consolidated statements of cash flows or the consolidated statements of changes in shareholder's equity.

The following table presents the carrying values of the major classes of assets held for sale and liabilities associated with assets held for sale included in OPG's consolidated balance sheets as at December 31, 2025:

As at December 31 *(millions of dollars)*	**2025**
Assets held for sale	
Cash, cash equivalents and restricted cash	**77**
Other current assets	**34**
Property, plant and equipment, net	**2,047**
Intangible assets, net and other non-current assets	**164**
Total assets held for sale	**2,322**
Liabilities associated with assets held for sale	
Accounts payable and other current liabilities	**32**
Debt	**296**
Other liabilities	**239**
Total liabilities held for sale	**567**

S&P Global
Ratings

RatingsDirect®

Ontario Power Generation Inc. 'BBB+' Rating Affirmed As Equity Commitments Support Growth

April 2, 2026

Rating Action Overview

- Ontario Power Generation Inc. (OPG) has secured equity commitments of C$5 billion from the Ontario provincial government towards its overall financing needs, and up to C$2 billion and C$1 billion from the Canadian federal government and the Ontario provincial government respectively to fund its small modular reactor (SMR) project, the Darlington New Nuclear Project (DNNP).
- OPG also filed a multiyear rate case with the Ontario Energy Board (OEB). S&P Global Ratings expects OPG to manage regulatory risk effectively.
- Therefore, we affirmed all our ratings on OPG, including our 'BBB+' issuer credit rating with a stable outlook.
- The stable outlook reflects our expectation that OPG will focus on its regulated business and contracted unregulated power business and that OPG will effectively manage its regulatory risk. The stable outlook also reflects our expectations that OPG will execute its major nuclear projects without material delays and within budget.

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Rating Action Rationale

Equity injections and asset sales will bolster OPG's financial profile as it funds projects. In October 2025, OPG secured up to C$3 billion from the provincial government through the Building Ontario Fund and the federal government through the Canada Growth Fund. These funds are earmarked for the company's SMR project, DNNP.

Further strengthening its financial position, in December 2025, the provincial government committed C$5 billion in equity injections through 2027 in the form of preferred shares. OPG has already received C$1 billion in 2025, and we anticipate the company will receive the remaining C$4 billion in over 2026 and 2027. Additionally, in January 2026, OPG sold its unregulated U.S. business for approximately $1.5 billion inclusive of debt assumed by the buyer.

We currently project annual capex of approximately C$7-C$8 billion per year through 2028, funding the refurbishment project of its Pickering Nuclear Generating Station (Pickering) (about C$10 billion total) and the DNNP project (about C$4 billion). We forecast funds from operations (FFO) to debt of approximately 20% in 2026, reflecting the positive impact of equity issuances

and the Eagle Creek sale, partially offset by expected lower nuclear production due to the planned shutdown of Pickering in late 2026. We expect minimal negative discretionary cash flow in 2026.

We anticipate FFO to debt will decline to around 17% in 2027 due to planned outages at the Darlington Nuclear Generating Station and the anticipated shutdown of Pickering, reducing power generated. However, we expect FFO to debt to recover to approximately 20% in 2028, assuming no outages at the Darlington Nuclear Generating Station, benefiting from our expectation of higher rate-regulated prices.

Current legislation would qualify projects such as the Pickering refurbishment and DNNP to receive a 15% tax credit, which could lower capital costs, but could also lower OPG's rate base. We will continue monitoring how this legislation will be treated by OPG's regulator, the Ontario Energy Board (OEB)

We exclude OPG's preferred shares from our adjusted debt calculations. We treat financing from a controlling shareholder, other than common equity, as either 100% debt or do not include it in our debt calculations. We exclude OPG's preferred shares from our adjusted debt calculation because we believe they lack key characteristics of debt. Specifically, these preferred shares do not require mandatory cash payments, offer no creditor protection to the sole shareholder, the province of Ontario, and provide no incentive for the issuer to redeem them. We anticipate any redemption of these preferred shares will be contingent on maintaining a financial risk profile that aligned with our rating.

OPG's proposed rate increases reflect large investments in OPG's generation fleet. In December 2025, OPG filed a multiyear rate plan covering 2027-2031 with the OEB, which will succeed its current multiyear plan ending in 2026. The requested increases will cover the refurbishment of the Pickering Nuclear Generating Station, an increase in Darlington's rate base following its refurbishment, and a request to increase the equity component of its capital structure to 52% from 45%. The rate request also incorporates higher operations and maintenance (O&M) costs and capex to address the aging regulated hydroelectric fleet.

Furthermore, OPG is seeking approval to recover the cost of the debt on Pickering and DNNP prior to their entry into service, as legislated. Notably, OPG is requesting that the build out of unit 1 of DNNP to be 100% funded by equity while only receiving a debt rate of return on it through the concurrent cost recover during construction (CCR), due to the first-of-kind risks associated with the new technology. We anticipate a decision from the OEB by the end of 2026.

OPG's large-scale nuclear projects introduce inherent risks of delays, operational challenges, and cost overruns, particularly concerning DNNP. Regarding the Pickering refurbishment, OPG has demonstrated a strong track record in project execution of a similar project. Specifically, it completed the Darlington refurbishment several months ahead of schedule and approximately C$150 million under budget. This success increases our confidence in OPG's ability to deliver the Pickering refurbishment on time and within budget, which remains our base-case scenario.

In contrast, DNNP's pursuit of new nuclear generation technology exposes OPG to operational and execution risks, potentially leading to cost overruns and losses, and in extreme cases, disallowance of costs. The BWRX-300 reactors in the SMRs represent first-of-kind technology, introducing uncertainty related to novel or significantly altered equipment, increasing the potential for unforeseen operational challenges. Therefore, we maintain a negative financial policy modifier for OPG, reflecting the potential for base-case financial measure projections to deviate due to the uncertainty surrounding DNNP.

Partially mitigating this risk over the next five years, unit 1 of the DNNP will be 100% equity funded. If unit 1, successfully operates upon completion, and pending regulatory and other approvals, OPG will commence nuclear power plant construction of units 2-4 after 2031 through a special purpose vehicle. We expect funding for these subsequent units, along with unit 1, to be funded by debt and equity in a conservative manner.

Our assessment of a high likelihood of government support is a key credit strength. OPG is of critical importance to the province as it generates about 50% of all the power generated in Ontario, and it is not easily replaceable. It also has a strong track record of support as the province has not taken out a regular dividend from OPG since 2006. The province's recently committed equity further demonstrates support. These factors underpin our high likelihood of support assessment.

The stand-alone credit profile (SACP) assessment of OPG is 'bb+'. A high likelihood of government supports an issuer credit rating at 'BBB+', three notches above the SACP

Outlook

The stable outlook on OPG incorporates our expectation for stable cash flow driven by its regulated business and contracted unregulated power business, as well as our expectation that OPG will effectively manage its regulatory risk. The stable outlook also reflects our expectations that OPG will execute its major nuclear projects without material delays and within budget. The stable outlook also reflects FFO to debt of 17%-20% through 2028.

Downside scenario

We could lower our ratings on OPG in the next 12-18 months if

- Its financial measures weaken, including FFO to debt consistently below 13%. This could occur if OPG experiences unforeseen operational challenges, delays, and cost overruns in its Pickering refurbishment or DNNP projects;
- It faces adverse regulatory decisions; or
- We downgrade the Province of Ontario by more than one notch or the relationship between OPG and the province unexpectedly deteriorates.

Upside scenario

We could raise our ratings on OPG in the next 24 months if:

- It improves its financial measures, including FFO to debt consistently above 20%; or
- We reassess the relationship between OPG and the province as higher than our high likelihood of support.

Company Description

OPG is an Ontario-based electricity generation company. The company's generation fleet comprises about 18,096 megawatts (MW) of capacity. OPG is wholly owned by the Province of Ontario.

Our Base-Case Scenario

Assumptions

- Gross margin decreases in 2026 and 2027 compared to 2025 due to the shutdown of Pickering in late 2026 and planned outages at Darlington, before increasing in 2028 from higher nuclear production and new regulated prices.
- EBITDA falls slightly by about 5% in 2026 due to the shutdown of Pickering, improves in 2027 due to higher regulated prices, and improves substantially in 2028 due to no outages at Darlington.
- There is minimal, negative discretionary cash flow in 2026 due to equity injections and the sale of Eagle Creek.
- Negative discretionary cash flow increases in 2027 and 2028 due to its robust capex of about C$7-C$8 billion per year.
- All debt maturities are refinanced.

Key metrics

Ontario Power Generation Inc.--Forecast summary

Period ending	Dec-31-2022	Dec-31-2023	Dec-31-2024	Dec-31-2025	Dec-31-2026	Dec-31-2027	Dec-31-2028
Adjusted ratios							
Debt/EBITDA (x)	3.2	3.7	4.6	3.5	3.5-4.0	4.0-4.5	3.5-4.0
FFO/debt (%)	25.9	19.8	16.4	25.5	19.0-21.0	16.0-18.0	19.0-21.0
FFO cash interest coverage (x)	8.2	6.9	5.7	7.7	5.0-5.5	5.0-5.5	5.5-6.0

Liquidity

As of Dec. 31, 2025, 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 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 C$3.2 billion various committed credit facilities that mature beyond 12 months 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 debt maturity is in 2026, when about C$675 million comes due, which we expect it will proactively address well in advance of the due date.

Principal liquidity sources	Principal liquidity uses
• Cash and liquid investments of about C$1.4 billion	• Debt maturities and commercial paper outstanding of about C$1.3 billion

- Credit facility of C$3.2 billion that mature beyond 12 months
- Estimated cash FFO of about C$2.7 billion;
- Eagle Creek Asset sale of about C$1.75 billion
- Working capital inflows of about C$80 million
- Capital spending of about C$7 billion

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.

Issue Ratings--Subordination Risk Analysis

Capital structure

OPG's capital structure comprises roughly C$12 billion of debt, of which about C$9.4 billion is senior unsecured 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	
Component	
Foreign currency issuer credit rating	BBB+/Stable/--
Local currency issuer credit rating	BBB+/Stable/--
Business risk	Strong
Country risk	Very low risk
Industry risk	Low risk
Competitive position	Strong
Financial risk	Significant
Cash flow/leverage	Significant
Anchor	bbb
Modifiers	
Diversification/portfolio effect	Neutral/Undiversified
Capital structure	Neutral
Financial policy	Negative
Liquidity	Adequate
Management and governance	Neutral
Comparable rating analysis	Negative
Stand-alone credit profile	bb+
Likelihood of government support	High (+3 notches from SACP)

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, July 7, 2025
- Criteria | Corporates | General: Methodology For Assessing Financing Contributed By Controlling Shareholders, May 15, 2025
- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013

- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Ratings List

Ratings List	
Ratings Affirmed	
Ontario Power Generation Inc.	
Issuer Credit Rating	BBB+/Stable/--
Senior Unsecured	BBB+
Commercial Paper	A-2
Commercial Paper	A-1(LOW)

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at https://disclosure.spglobal.com/ratings/en/regulatory/ratings-criteria for further information. A description of each of S&P Global Ratings' rating categories is contained in "S&P Global Ratings Definitions" at https://disclosure.spglobal.com/ratings/en/regulatory/article/-/view/sourceId/504352. Complete ratings information is available to RatingsDirect subscribers at www.capitaliq.com. All ratings referenced herein can be found on S&P Global Ratings' public website at www.spglobal.com/ratings.

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MORNINGSTAR | DBRS

PRESS RELEASE

APRIL 10, 2026

Morningstar DBRS Confirms Credit Ratings on Ontario Power Generation Inc. at A (low) and R-1 (low) With Stable Trends

UTILITIES & INDEPENDENT POWER

DBRS Limited (Morningstar DBRS) confirmed Ontario Power Generation Inc.'s (OPG or the Company) Issuer Rating and Unsecured Debt credit rating at A (low) and its Commercial Paper credit rating at R-1 (low). All trends are Stable.

KEY CREDIT RATING CONSIDERATIONS

Morningstar DBRS' credit ratings on OPG are based on the Company's regulated generation business, which operates under a reasonable regulatory regime under the Ontario Energy Board (OEB). The Stable trends reflect Morningstar DBRS' expectations that the Company's key credit metrics will remain adequate for the current credit rating category, despite the complex and substantial capital expenditures (capex) program.

OPG has several ongoing large capital projects. The Darlington Refurbishment Project effectively moved into closeout, with four units completed four months ahead of schedule and approximately $150 million under budget. The project secures 3,512 megawatts of low-carbon capacity for more than 30 years. The Pickering Refurbishment Project advanced to a pre-execution phase, with provincial approval granted to the Company in November 2025 to proceed with refurbishing Units 5 to 8. The project budget for the four units is $26.8 billion and includes interest, cost escalation, and contingency. The Darlington New Nuclear Project (DNNP) transitioned to the construction phase and represents the Province of Ontario's (Ontario or the Province, rated AA with Stable trend) first grid-scale small modular reactor (SMR) project in North America. The budget for Unit 1 plus shared four-unit infrastructure is $7.7 billion, with the four-unit project estimated at approximately $20.9 billion and includes interest, cost escalation, and contingency.

The Company is also investing in upgrading and optimizing its existing hydroelectric assets to meet emerging demand as the Province continues to electrify. Additionally, the wholly owned subsidiary Atura Power, as part of OPG's nonregulated segment, is constructing several growth capex projects.

CREDIT RATING DRIVERS

A positive credit rating action would require a material improvement in OPG's business risk profile while maintaining the financial risk profile. Morningstar DBRS may consider a negative credit rating action if OPG's business risk profile were to deteriorate significantly, or its metrics were to sustainably weaken to a level below the A (low) credit rating category (i.e., cash flow-to-debt below 10%).

EARNINGS OUTLOOK

OPG's net income attributable to the shareholder increased to $1,509 million in 2025 from $988 million in 2024, primarily reflects higher nuclear generation from Unit 1 of Darlington Nuclear Generation Station returning to service in November 2024 and fewer planned outages. OPG's earnings outlook remains

supported by its regulated nuclear and hydroelectric operations, but, beyond 2026, earnings projections are increasingly tied to the outcome of its current OEB proceeding. OPG filed a five-year application in December 2025 for new regulated prices for electricity generated from the Company's regulated operations, including for the DNNP SMR facilities, with a proposed effective date of January 1, 2027.

FINANCIAL OUTLOOK

Given several ongoing significant capex plans, OPG forecasts a capex increase to approximately $7 billion-$8 billion annually over 2026-28. OPG completed the sale of its Eagle Creek business in the U.S. in January 2026, with the net proceeds of the sale being used toward 2026 capex needs. Provincial support for OPG strengthened in late 2025, with the Province committing $5 billion of equity injections over 2025-27 and providing an initial $1 billion in December 2025. Together with up to $3 billion of project level equity commitments from federal and provincial government agencies toward DNNP, these supports are credit positive and should help fund OPG's elevated capital program. 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 and expect the key credit metrics to remain reasonable for the A (low) credit rating.

CREDIT RATING RATIONALE

OPG's credit ratings are supported by the reasonable regulatory framework that provides stable cash flow, support from the Province, and limited nuclear waste management liabilities. This is offset by nuclear generation risk, risk of political intervention, the significant capex program, and a high cost base that has historically resulted in reductions in allowable costs through regulated rate setting.

Comprehensive Business Risk Assessment (CBRA)

OPG's CBRA of AL reflects (1) its stable regulated businesses with supportive regulatory frameworks to allow the Company to recover prudently incurred costs and provide stable cash flows, (2) Ontario's largest and one of North America's most diverse electricity generators, and (3) the Company's dominant market position and large and diversified customer base in Ontario.

Comprehensive Financial Risk Assessment (CFRA)

The CFRA of A reflects OPG's strong key credit metrics, supported by the stable cash flow generated from its regulated business and provincial equity injection commitment. We note that the Company's pro forma revenues for 2027 and 2028 reflect the anticipated rebasing of regulated rates effective January 1, 2027. The CFRA factors negative two notches adjustment for OPG's large capex in the foreseeable future and complexity of capital-intensive SMR build out.

Intrinsic Assessment (IA)

The IA midpoint of AL is within the IA Range; it is based on the CBRA and CFRA and takes into consideration the current credit rating trend and peer comparisons, among other factors.

Additional Considerations

The credit rating includes a positive half notch adjustment reflects implicit support from the Province.

ENVIRONMENTAL, SOCIAL, AND GOVERNANCE CONSIDERATIONS

There were no Environmental/Social/Governance factors that had a significant or relevant effect on the credit analysis.

A description of how Morningstar DBRS considers ESG factors within the Morningstar DBRS credit rating framework can be found in the Morningstar DBRS Criteria: Approach to Environmental, Social, and Governance Factors in Credit Ratings (May 16, 2025) https://dbrs.morningstar.com/research/454196.

Further details on the Issuer's Intrinsic Assessment can be found at https://dbrs.morningstar.com/research/478549.

Notes:
All figures are in Canadian dollars unless otherwise noted.

Morningstar DBRS applied the following principal methodology:
-- Global Methodology for Rating Companies in the Regulated/Nonregulated Utility and Independent Power Producer Industries (November 25, 2025), Regulated Utility Industry Supplement https://dbrs.morningstar.com/research/467973

Morningstar DBRS credit ratings may use of one or more sections of the Morningstar DBRS Global Corporate Criteria (December 19, 2025) https://dbrs.morningstar.com/research/470156, which covers, for example, topics such as holding companies and parent/subsidiary relationships, guarantees, recovery, and common adjustments to financial ratios.

The following methodologies have also been applied:
-- Morningstar DBRS Criteria: Approach to Environmental, Social, and Governance Factors in Credit Ratings (May 16, 2025) https://dbrs.morningstar.com/research/454196

The credit rating methodologies used in the analysis of this transaction can be found at: https://dbrs.morningstar.com/about/methodologies.

A description of how Morningstar DBRS analyzes corporate finance transactions and how the methodologies are collectively applied can be found at: https://dbrs.morningstar.com/research/431153.

The related regulatory disclosures pursuant to the National Instrument 25-101 Designated Rating Organizations are hereby incorporated by reference and can be found by clicking on the link under Related Documents or by contacting us at info-DBRS@morningstar.com.

The credit ratings were initiated at the request of the rated entity.

The rated entity or its related entities did participate in the credit rating process for this credit rating action.

Morningstar DBRS had access to the accounts, management, and other relevant internal documents of the rated entity or its related entities in connection with this credit rating action.

This is a solicited credit rating.

For more information on Morningstar DBRS' policy regarding the solicitation status of credit ratings, please refer to the Credit Ratings Global Policy, which can be found in the Morningstar DBRS Understanding Ratings section of the website: https://dbrs.morningstar.com/understanding-ratings

The conditions that lead to the assignment of a Negative or Positive trend are generally resolved within a 12-month period. Morningstar DBRS trends and credit ratings are under regular surveillance.

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Ratings

Ontario Power Generation Inc.

Date Issued	Debt Rated	Action	Rating	Trend	Attributes
10-Apr-26	Issuer Rating	Confirmed	A (low)	Stb	CA
10-Apr-26	Unsecured Debt	Confirmed	A (low)	Stb	CA
10-Apr-26	Commercial Paper	Confirmed	R-1 (low)	Stb	CA

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Exhibit L
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Attachment 3
Page 5 of 5

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30 September 2022

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RATINGS

Ontario Power Generation Inc.

Domicile	Ontario, Canada
Long Term Rating	A3
Type	Senior Unsecured -Dom Curr
Outlook	Stable

Source: Moody's Investors Service

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Ontario Power Generation Inc.

Nuclear refurbishment and life extension would be credit positive for Ontario Power Generation

On 29 September, the Province of Ontario announced an effort to extend the life of Ontario Power Generation Inc's (OPG A3 stable) Pickering nuclear generating station by almost one year to the end of September 2026, and asked OPG to launch a study to evaluate the long-term feasibility of refurbishing the station for additional life extension. The measures are credit positive because refurbishment could extend the life of the units for decades and the extension would add to the company's 2026 cash flow.

Assuming the refurbishment proceeds and is completed, the units would generate power at regulated prices for their remaining life, generating long term stable cash flow, a credit positive. The Province of Ontario asked OPG to consider refurbishing Units 5-8, which could lead to an additional 30 years of operation. OPG expects to submit a final recommendation on refurbishment – including its timeline and estimated cost – to the Province within the next year. The units' life extensions beyond 2026 would require their complete refurbishment. OPG expects to record the costs of the study in a variance account and recover them in customer rates at a later date subject to a prudence review by the regulator, the Ontario Energy Board (OEB).

OPG is establishing a track record for executing its current nuclear refurbishments, which have a very high level of execution risk. The company's current CAD12.8 billion refurbishment of all four units at its Darlington nuclear generating station is largely on budget, and refurbishment of the most recent unit is ahead of schedule. OPG indicated that it is tracking to its budget with the exception of Covid-related effects. Darlington's Unit 3 was originally forecast to complete refurbishment in the first quarter of 2024, but management now expects completion by year-end 2023. The Darlington refurbishment demonstrates that a supply chain and well-trained workforce are available to undertake refurbishment work.

Operating Pickering Units 5-8 until September 2026 would lead to more power generation than previously forecast and increase OPG's revenue and cash flow in 2026. In the second half of 2021, OPG reached a settlement with its intervenors that was subsequently approved by the OEB. The settlement establishes regulated nuclear power generation prices for 2022-26. The 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. The price that OPG receives for nuclear power in 2026 was set at $118.91 per MWh. There are no proposed changes to units 1 and 4, which will be shut down in 2024 and placed in safe storage prior to decommissioning.

The Province is seeking to extend that life of the units because extending the life of the units would address the Province's increased demand and power shortage that the Independent Electricity System Operator (IESO, Aa3 stable) has identified. OPG believes that it can safely operate units 5-8 in 2026 and expects to submit a license application to the Canadian Nuclear Safety Commission (CNSC) over the next year to extend the life of Pickering Units 5-8 to the end of September 2026 from the currently approved date of 31 December 2024. The Province has previously expressed it desire to have the units operate through the end of 2025. The CNSC has approved the operations their currently approved date of 31 December . The CNSC will make the final decision regarding the life extension.

Exhibit 1

Pickering nuclear generating station key characteristics

Pickering A	Capacity (MW)	Commission date	Shutdown date	Refurbishment complete	Status
Unit 1	515	1971	1997	2005	Shutdown in Sept 2024
Unit 2	515	1971	1997		Decommissioned 2007
Unit 3	515	1972	1997		Decommissioned 2008
Unit 4	515	1973	1997	2003	Shutdown in Dec 2024
Pickering B					
Unit 5	516	1983			possible life extension to end of Sept 2026 and refurbishment
Unit 6	516	1984			possible life extension to end of Sept 2026 and refurbishment
Unit 7	516	1985			possible life extension to end of Sept 2026 and refurbishment
Unit 8	516	1986			possible life extension to end of Sept 2026 and refurbishment

Source: Company filings

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Filed: 2026-04-22
EB-2025-0297
Exhibit L-A2-Staff-010
Attachment 5, Page 1 of 5

ISSUER COMMENT
9 April 2025

Send Your Feedback

Ontario Power Generation Inc.

License to build small modular reactor entails very high execution risk

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On 4 April, the Canadian Nuclear Safety Commission (CNSC) issued a license to Ontario Power Generation Inc. (OPG, A3 stable) to construct one BWRX-300 reactor at its Darlington New Nuclear Project (DNNP) site. Because the project carries very high execution risk, it will put pressure on OPG's financial profile, a credit negative.

New nuclear projects in Europe and North America have a poor track record on construction. Recent large-scale nuclear power plants have been plagued by significant delays and cost overruns. Although OPG has indicated that the BWRX-300 small modular reactor (SMR) will use established technology, the build will be the first of its kind in the G-7 countries, which in itself entails execution risk.

Nevertheless, OPG's track record on its nuclear refurbishment projects is strong and has exceeded our expectations. The company expects to complete its 10-year CAD12.8 billion refurbishment of all four reactors at the Darlington nuclear generating station on budget. Most recently, Darlington Unit 1 returned to service after its refurbishment was completed five months ahead of schedule, and the final unit is likely to return to service in 2026.

While the assets will form part of the regulated fleet, OPG has yet to release a cost estimate for the SMR project and as yet lacks clarity on the degree and timing of the regulatory support (if any) it will receive for the project during construction. This lack of clarity adds uncertainty to the company's financial profile, including the trajectory of its key cash flow from operations before changes in working capital (CFO Pre-W/C) to debt metric. We expect the company to disclose an SMR cost estimate in the coming weeks or months now it has received the license to construct, and anticipate that a funding strategy will follow.

In addition, OPG is moving forward with additional nuclear refurbishments of four units at its Pickering generating station without a cost estimate or specific regulatory support provisions. We expect the company to seek regulatory support for both projects, and such support could reduce the pressure on its financial profile. The receipt of the license to construct is in line with our expectations and our assessment of the company's current financial profile assumes that progress on the DNNP will occur with credit-supportive regulation.

The ability to advance large projects without a public cost estimate and certainty on the degree of regulatory support during construction differentiates government-owned OPG from investor-owned utilities. However, similar to investor-owned utilities, we expect OPG to consider multiple levers to finance its large capital plan, including the potential sale of non-core assets, equity, hybrid securities and debt issuance.

OPG is owned by the Province of Ontario (Aa3 positive) and has its support in building SMRs. The province has pointed to the economic benefits, reliability of nuclear power and affordability as part of its rationale for supporting such projects. In addition, although the

license only allows for the construction of one SMR, the province is supportive of OPG's plan to build four SMRs on the site using the same technology in an effort to generate economies of scale. OPG has indicated that it will not begin nuclear construction on subsequent units until the first unit is completed, likely in 2030, so that it may incorporate lessons learned. We expect execution risk will decline with subsequent units.

The first nuclear generating units to be refurbished in Ontario were refurbished by Bruce Power L.P. (Baa2 stable) more than a decade ago and were not completed on time or within budget. Lessons learned from these units have benefited all subsequent unit refurbishments. Both Bruce Power and OPG have since been successful in implementing their refurbishment programs.

The license to construct is the latest milestone the DNNP project has reached. In December 2021, OPG announced that it had selected the GE Hitachi BWRX-300 design and it applied to the CNSC for a construction license in October 2022. We believe a significant number of utilities are closely following OPG's progress and that its license may lead other utilities to follow suit on a similar basis in the US. The US Nuclear Regulatory Commission and CNSC have had a working relationship for several years, which should expedite implementation of the design in the US.

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ISSUER IN-DEPTH
26 June 2025

Send Your Feedback

Ontario Power Generation Inc.

Government support for nuclear construction would be credit positive

RATINGS

Ontario Power Generation Inc.	
Senior unsecured rating	A3
Outlook	Stable

Summary

On 8 May 2025, the Province of Ontario (Aa3 stable) announced that Ontario Power Generation Inc. (OPG, A3 stable) will proceed with the construction of four 300-megawatt (MW) small modular reactors (SMRs) on a site adjacent to OPG's Darlington nuclear generating station. The utility expects to connect the first unit to the grid in 2030. The provincial government is concluding a 45-day public comment period seeking feedback on proposed regulatory changes that would allow concurrent cost recovery for nuclear construction, as well as allow OPG to sell a portion of the Darlington SMR project to investors. Such measures would be credit positive for the utility, but their financial benefit will depend on key assumptions.

» **Very high level of execution risk associated with new nuclear projects.** Nuclear operators have a poor track record of completing the construction of new nuclear capacity on time and within budget. Delays are often measured in years and cost overruns in the billions of dollars. While we expect OPG to recover prudently incurred costs, we may not know whether the company will be able to recover any potential cost overruns until the Darlington SMR project is completed.

» **Gradual capacity expansion should reduce risk of cost overruns.** To reduce execution risk, OPG plans to build out capacity at the Darlington nuclear site by constructing unit 1 first and applying lessons learned to the construction of subsequent units. By applying lessons learned, the utility expects each unit's capacity cost to decline as the construction proceeds. Even if these cost savings fall short of the company's forecast, the gradual expansion of generating capacity should reduce the risk of cost overruns associated with the construction of large nuclear power plants.

» **Concurrent cost recovery and other forms of regulatory support would be credit positive.** Concurrent cost recovery would be credit positive because, as contemplated by the government, it would provide some cash flow during the construction phase of both the Darlington SMR and Pickering refurbishment projects. How supportive this would be for OPG's credit profile would depend on how the recovery of costs is implemented.

» **Other direct forms of government support may also be credit supportive.** Allowing OPG to sell an ownership interest in the Darlington SMR project would be credit positive because it could reduce its overall investment in the project and reduce the pressure that it would otherwise place on the balance sheet. The province and the federal government could also provide support to OPG during construction, such as through tax incentives, direct equity injections, below-market loans or loan guarantees and a funding cap, all of which we have seen in other jurisdictions.

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Very high level of execution risk associated with new nuclear projects

Government support for the construction of the Darlington SMRs is important, given the substantial execution risks associated with first-of-a-kind nuclear projects. Nuclear operators have a poor track record of completing the construction of new nuclear capacity on time and within budget. Delays are often measured in years and cost overruns in the billions of dollars. Moreover, poor execution of the first Darlington SMR may erode public, political and regulatory support for subsequent units.

First-of-a-kind projects are characterized by high technology risk that can exacerbate execution risks. The GE Hitachi BWRX 300 SMR that OPG has selected is based on a 10th generation boiling water reactor technology, although it would be the first SMR project undertaken by OPG and its partners. We expect OPG to recover prudently incurred costs under the current regulatory framework. However, until the project is completed, we may not know whether the company will be able to recover cost overruns, if any. There is also the possibility of some cost sharing with contractors. But the scale of cost overruns on other first-of-a-kind projects suggest that such arrangements are unlikely to be material to OPG's credit quality.

The province's Darlington SMR announcement comes at a time when OPG also plans to refurbish existing generating units at the utility's Pickering nuclear generating station, subject to final approvals. The cost of the refurbishment and the level of regulatory support OPG will receive during construction have not been determined, heightening the uncertainty facing the utility.

Gradual capacity expansion should reduce risk of cost overruns

To reduce the execution risks associated with building the first commercially viable SMR facility in North America, OPG plans to build out capacity at the Darlington nuclear site by constructing unit 1 first and applying lessons learned to the construction of subsequent units. We expect that the construction of subsequent units will overlap, and the utility expects to apply lessons learned from each unit to subsequent units. OPG expects this "fleet approach" to the project's construction to drive down costs of subsequent units. The utility expects the first unit to deliver power to the grid in 2030 and complete all of the construction of all four units by the mid 2030s.

Common costs of $1.6 billion must be spent before the first SMR can generate power and deliver it to the grid. As shown in Exhibit 1, the government forecasts a decline in the capacity cost of each SMR as the Darlington project proceeds and expects Unit 4's capacity cost to be about a third less than that of Unit 1. There is a meaningful risk that these cost savings do not materialize, or not to the extent that the company projects.

Exhibit 1

The Ontario government expects the cost of each successive SMR at the Darlington site to decline

	Cost (CAD billions)	Capacity (MW)	Capacity cost (CAD millions per MW)*	Capacity cost ($** millions per MW)*
Unit 1	6.1	300	21.7	15.7
Unit 2	4.9	300	17.7	12.8
Unit 3	4.2	300	15.3	11.1
Unit 4	4.1	300	15.0	10.9
Unit 4 (excluding common costs)			13.7	9.9
Common costs	1.6			
Total Costs	20.9			

*Includes equal sharing of common costs
**Exchange rate of $1.00=CAD1.38
Source: Government of Ontario

Each SMR unit is considerably lower in total cost compared to larger nuclear units that are often about 1 gigawatt (GW) in size, so cost overruns on a single unit are not likely to be as large in nominal terms. OPG expects that each unit will be added to rate base and generate cash flow as completed. This compares favorably to large units, where the investment per unit is much larger, placing more pressure on the balance sheet during construction. This, in combination with what can be a long period of time to complete

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larger units, exacerbates pressure on the balance sheet from large units. However, the ability to complete construction of SMRs within a shorter time frame than that of a traditional nuclear generating unit remains unproven. Our expectation is that prudently incurred costs will be added to rate base and be recovered in rates upon the completion of the units.

In recent years, OPG has developed a strong track record as a nuclear power generator. The utility is approaching the completion of its decadelong CAD12.8 billion refurbishment of its four-unit Darlington nuclear power generating station on budget and we expect likely ahead of schedule in 2026. However OPG had the opportunity to learn from the refurbishment of Bruce Power L.P.'s (Baa2 stable) first two units about 15 years ago, and the refurbishment of those earlier units was neither on time nor on budget.

Concurrent cost recovery and other forms of regulatory support would be credit positive

The key forms of regulatory support that we expect to be considered either through the government feedback process or during OPG's next rate case include concurrent cost recovery (cash construction work in progress, or CWIP), recovery of preconstruction costs, higher equity capital and a higher return on equity.

Concurrent cost recovery would be credit positive because, as contemplated by the government, it would provide some cash flow during the construction phase of both the Darlington SMR and Pickering refurbishment projects. In addition, it would somewhat alleviate upward pressure on customer rates that would likely occur when the SMRs are brought into service because the company had been recovering its cost of capital in rates, leading to a lower rate base when the asset is ultimately placed into service.

Under the proposal being considered, OPG could recover debt interest costs associated with both projects during the construction phase. Instead of capitalizing interest expense, the company would recover those amounts in rates during the construction period when pressure on financial metrics from these projects is greatest.

How supportive this would be for OPG's credit profile would depend on how the recovery of costs is implemented. Capitalized costs are typically recovered over the life of the assets. Concurrent cost recovery that is based on forecast capital expenditures and adjusted to reflect actual spend would be more beneficial than a lagging – and likely lower – capital expenditure figure. Recovery based on a weighted average cost of capital that includes the company's interest expense and return on equity would be more beneficial. Less credit supportive would be cash flow recovered in rates that is based on a short-term or long-term debt rate (as proposed by government) that is less than the weighted average cost of capital.

Some recovery of capital investments during the construction period would also provide significant credit support to the utility. In conjunction with concurrent cost recovery, this could mimic rate base investment and these investments could put negligible pressure, if any, on financial metrics, if the investments are recovered at a level that approximates depreciation. Faster recovery of investments would be even more credit friendly. We seldom see this considered by regulators who often take the view that rate payers who benefit from a project placed in service should pay for it. This approach lends itself to cash recovery once a project is in service. However, it may also ignore the significant economic benefits incurred during the construction of the project.

OPG is already recovering some preconstruction costs in customer rates, which is credit positive. In June 2024, the Ontario Energy Board approved the recovery of CAD108 million from 1 July 2024 through the end of 2026. These costs were associated with the noncapital preliminary planning and preparation costs that were incurred between 2020 and 2022. Any recovery that the company receives before or during the construction period would be credit positive. Carrying costs on costs recovered before or during construction are lower because they are recovered sooner (instead of capitalizing an annual return on these costs until the asset is placed into service) and cash flow during construction would be credit supportive during the construction period.

Higher equity capital and a higher return on equity would likely be only modestly supportive

A higher equity thickness in the deemed capital structure only on the construction project would be modestly credit positive. While it does reduce the amount of debt on OPG's balance sheet, the company may have to provide additional equity. Also, this may lead to a higher weighted average cost of capital that, unless there is some form of CWIP, would drive project costs even higher. Higher equity capital on other, existing assets that are in service and generating cash flow would be significantly more credit positive than a higher equity layer on assets under construction that are not generating cash flow.

Similarly, a higher return on equity (ROE) on the construction project itself would have limited credit benefits unless it is combined with cash CWIP (using a weighted average cost of capital that includes ROE) or is applied to operating assets that would drive increased cash flow.

Other direct forms of government support may also be credit supportive

Allowing OPG to sell an ownership interest in the Darlington SMR project would be credit positive because it could reduce its overall investment in the project and reduce the pressure that it would otherwise place on the balance sheet. A key consideration would be the allocation of project costs and any cost overruns or delays. If project costs and any cost overruns are borne by co-owners in proportion to their ownership interest, this would be more credit positive than selling an ownership interest where OPG retains a larger share of exposure to cost overruns. Clear governance provisions among the investors would be key to understanding the credit risks under this type of arrangement.

The province could also provide support to OPG during construction, such as through tax incentives, direct equity injections, below-market loans or loan guarantees and a funding cap, similar to those found in other jurisdictions. Because we expect investments in SMRs to be added to rate base, price support mechanisms like contracts for difference or long-term power purchase agreements are not relevant to OPG.

Tax incentives that reduce taxes payable during construction and increase cash flow would be credit positive. Direct equity injections to OPG would be beneficial to the extent that they reduce the amount of debt we would otherwise expect the company to incur. Below-market loans or loan guarantees that reduce the company's interest expense and increase its cash flow would also be supportive, although we would likely consolidate the debt. A funding cap that shifts cost overruns beyond a predefined point from OPG to government would alleviate risk. Finally, long-term regulatory and policy certainty, which we believe OPG has, that addresses the potential for long-term shifts away from nuclear power generation would mitigate this risk.

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Tear Sheet:

Ontario Power Generation Inc.

July 25, 2023

Ontario Power Generation Inc.'s (OPG) Darlington refurbishment project is on time and on budget. The company recently announced that it successfully completed the refurbishment of 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 by 30 years. The company remains on track to complete the refurbishment of the remaining Darlington units by 2026 within the total budget of $12.8 billion. In addition, OPG also continues to assess and seek ways to manage the impact of the COVID-19 pandemic on the total cost of the project. The early return of Unit 3 will modestly improve OPG's cash flow.

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 has 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 has provided a $970 million commitment toward funding 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 its recovery is based on rate-regulated mechanisms to preserve its credit quality.

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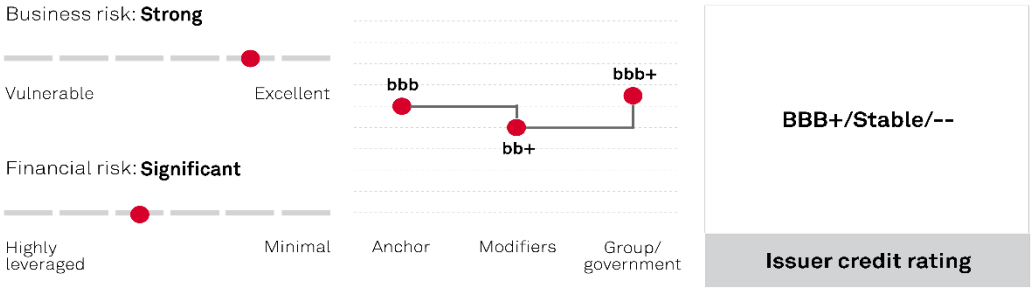
Ratings Score Snapshot



Company Description

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OPG is an Ontario-based electricity generation company. The company's generation fleet comprises about 18,100 MWs of capacity. OPG is wholly owned by the Province of Ontario.

Outlook

The stable outlook on OPG incorporates our expectation for more stable cash flows, our belief 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 its funds from operations (FFO) to debt will be in the 13.0%-15.5% range.

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 delays 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 above 20%.

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
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)
Plus/(less): Other	--	--	--	--	--	--	--	--
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.

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Financial Summary

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
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

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/--

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Ontario Power Generation Inc.--Peer Comparisons

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)	2,585	2,177	561
Interest	381	525	158
Cash interest paid	369	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)	8.0	4.7	4.6
Debt/EBITDA (x)	3.2	5.4	5.7
FFO/debt (%)	25.8	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

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 OPG 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

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exposes it to water resource risk. Social factors are a moderately negative consideration in our credit rating analysis based on the health and safety risks related to its nuclear generation.

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

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- 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

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Tear Sheet:

Ontario Power Generation Inc. License To Build Small Modular Reactor Is Credit Neutral

April 14, 2025

This report does not constitute a rating action.

What's new: The Canadian Nuclear Safety Commission recently issued Ontario Power Generation Inc. (OPG) a license to build the country's first small modular reactor (SMR). OPG intends to build a GE-Hitachi Nuclear Energy Inc. BWRX-300 reactor at the Darlington nuclear plant site in Clarington, Ontario. The license is valid until March 31, 2035. OPG plans to install four BWRX-300 SMRs at the site. The BWRX-300 is a boiling water reactor design that uses natural circulation for cooling. However, the decision does not authorize the operation of a BWRX-300 at the site. That would be subject to a future commission licensing hearing and decision.

Why it matters: This is a key milestone for the project as it shows continued confidence from the Canadian nuclear regulator in OPG to execute this project. The next step is for the Province of Ontario to approve the company to commence nuclear construction. We generally view the building of SMRs as negative for credit quality since it entails potential construction risk due to its first-of-its-kind technology. Developing new nuclear power plants is a highly complex project characterized by extensive timelines, significant capital investments, and inherent execution risks that can lead to significant cost overruns and delays. However, the Canada Infrastructure Bank provided a $970 million commitment to fund the project. Additionally, we expect the company to benefit from direct or indirect federal government incentives including applicable clean energy investment tax credits to partially fund these investments.

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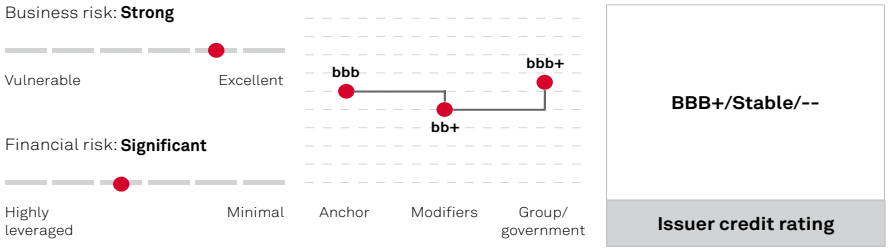
Ratings Score Snapshot



Recent Research

- Full Analysis: Ontario Power Generation Inc. , Aug. 14, 2024

Company Description

OPG is an Ontario-based electricity generation company. The company's generation fleet comprises about 18,225 megawatts (MW) of capacity. OPG is wholly owned by the Province of Ontario.

Outlook

The stable outlook on OPG incorporates the following expectations: more stable cash flows, no significant acquisitions, effective management of its regulatory risk, and that OPG will complete its future nuclear investments including refurbishments and small modular reactors on time and on budget. We also forecast funds from operations (FFO) to debt of 14%-16%.

Downside scenario

We could lower our ratings on OPG within the next 12-18 months if its financial measures weaken, including FFO to debt consistently below 13%. This could occur if the company experiences delays and cost overruns in its Darlington refurbishment program, faces adverse regulatory decisions, or undertakes significant debt-funded acquisitions. Alternatively, we could lower our rating if we downgrade the Province of Ontario or the relationship between OPG and the province unexpectedly deteriorates.

Upside scenario

Although highly unlikely, we could raise our ratings on OPG within the next 24 months if there is no change to its relationship with the Province of Ontario, it doesn't expand its nonutility businesses through acquisitions, and it materially improves its financial measures, including FFO to debt consistently more than 20%.

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Rating Component Scores	
Foreign currency issuer credit rating	**BBB+/Stable/--**
Local currency issuer credit rating	**BBB+/Stable/--**
Business risk	**Strong**
Country risk	Very Low
Industry risk	Low
Competitive position	Strong
Financial risk	**Significant**
Cash flow/leverage	Significant
Anchor	**bbb**
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Negative (-1 notch)
Liquidity	Adequate (no impact)
Management and governance	Neutral (no impact)
Comparable rating analysis	Negative (-1 notch)
Stand-alone credit profile	**bb+**

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, April 4, 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013

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Tear Sheet:

Ontario Power Generation Inc.'s Recent And Expected Updates Are Key To Maintaining Its Credit Quality

December 3, 2025

This report does not constitute a rating action.

What's new: Recent announcements by Ontario Power Generation Inc. (OPG) highlight the significant credit considerations related to its nuclear refurbishment program and funding strategy. Last week, the utility announced a C$26.8 billion cost estimate for the refurbishment of its Pickering Nuclear Generating Station (Pickering), with its refurbishments of Units 5-8 slated to begin by early 2027. OPG currently projects it will return Units 5-8 to service by the mid-2030s.

OPG continues to emphasize its commitment to securing credit-supportive funding to underpin its robust capital expenditure (capex) plans, which include up to C$3 billion of equity investments from the Canada Growth Fund and the Building Ontario Fund. Furthermore, the utility is exploring an additional C$5 billion equity injection from the Ontario Provincial government over the 2025-2027 period.

Other key updates include OPG's plan to file a rate case with the Ontario Energy Board (OEB) this year to cover its rates in 2027-2031 (consistent with our expectations), the potential for Federal Investment Tax Credits (could be legislated in 2026), and the possible implementation of concurrent cost recovery for the cost of debt of the Pickering Refurbishment and the Small Modular Nuclear Reactors ([SMR] known as the Darlington New Nuclear Project) during construction, which was proposed by the Ontario Provincial Government in May.

Why it matters: OPG's successful execution of its nuclear projects--including its SMR project -- receipt of credit-supportive funding, and effective management of its regulatory risk will be critical for its long-term credit quality. We currently forecast the utility's financial metrics will be in the middle of our expected range for the significant financial risk category through 2025 and 2026, with funds from operations (FFO) to debt of about 18%, supported by the near-full operational status of its nuclear generation fleet until the fourth quarter of 2026. However, as it takes Pickering Units 5-8 offline from early 2027 onward while ramping up its capex, we expect OPG's financial measures will weaken toward the lower end of our expected range for its financial risk category. Over the next decade, OPG anticipates spending approximately C$48 billion on the Pickering refurbishment and its SMR project. Therefore, the utility's funding strategy and the

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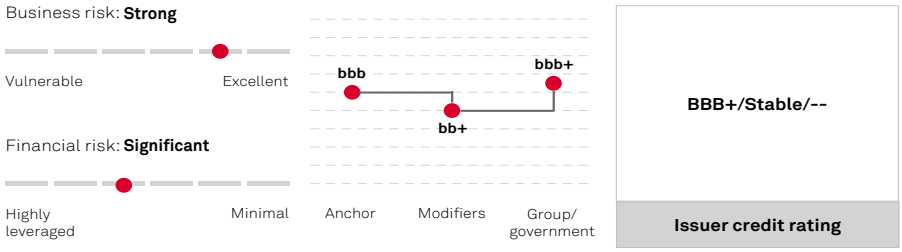
clarity surrounding it will be critical determinants of its ability to maintain its current credit quality.

The key items we are monitoring include equity funding, rate-case outcomes, concurrent cost recovery, and Federal Investment Tax Credits. Our current base-case forecast assumes OPG will remain committed to securing credit-supportive funding and effectively managing its regulatory risk during its upcoming rate case filing. We believe that successful execution of the utility's nuclear projects, especially around new technologies like SMRs, will be vital to support the current ratings.

Ratings Score Snapshot



Company Description

OPG is an Ontario-based electricity generation company. The company's generation fleet comprises about 18,094 megawatts (MW) of capacity. OPG is wholly owned by the Province of Ontario.

Outlook

The stable outlook on OPG incorporates our expectation for more-stable cash flows, no significant acquisitions, effective management of its regulatory risk, and the on-time and on-budget completion of its future nuclear investments, including its refurbishments and SMR project. We also forecast the utility's FFO to debt will be in the 15%-19% range through 2027.

Downside scenario

We could lower our ratings on OPG in the next 12-18 months if its financial measures weaken, including FFO to debt of consistently below 13%. This could occur if the utility experiences delays and cost overruns in its Pickering 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 in the next 24 months if there are no changes to its relationship with the Province of Ontario, it doesn't expand its nonutility

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businesses through acquisitions, and it materially improves its financial measures, including FFO to debt of consistently above 20%.

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**
Modifiers	
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Negative (-1 notch)
Liquidity	Adequate (no impact)
Management and governance	Neutral (no impact)
Comparable rating analysis	Negative (-1 notch)
Stand-alone credit profile	**bb+**

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, July 7, 2025
- Criteria | Corporates | General: Corporate Methodology, Jan. 7 2024
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7 2024
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10 2021
- 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 24 2015
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19 2013
- General Criteria: Methodology: Industry Risk, Nov. 19 2013
- General Criteria: Principles Of Credit Ratings, Feb. 16 2011

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VECC Interrogatory #005

Interrogatory

Reference:
Exhibit A2-3-1 Attachment 13 et al

Question(s):

a) If OPG has been provided a S&P Global Ratings in 2025 please provide that document.

Response

a) Refer to Ex. L-A2-Staff-010, part b).