Ontario Energy Board | Commission de l'énergie de l'Ontario

BY E-MAIL

March 25, 2026

Mr. Ritchie Murray
Acting Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4
Registrar@oeb.ca

Dear Ritchie Murray:

Re: Ontario Power Generation Inc. (OPG) and DNNP LP (the Applicants)
2027-2031 Payment Amounts
Ontario Energy Board (OEB) File Number: EB-2025-0297

In accordance with Procedural Order No. 2, please find attached the Ontario Energy Board (OEB) staff interrogatories in the above proceeding. The applicants and intervenors have been copied on this filing.

By letter dated March 6, 2026, and in the cover letter to the March 11, 2026 interrogatories, OEB staff identified certain aspects of the evidence where OEB staff retained external experts to assist OEB staff. The interrogatories in this batch were prepared by or in coordination with these external experts.

Three interrogatories included in this batch have related attachments, which are detailed below:

- A1-03-Staff-292: two Excel files: Table 1; Table 2a-b
- C1-01-Staff-302: RiderGEN_capitalstructure_testimony_2024; RiderGEN_Decision_2025
- C1-01-Staff-303: AmerenCorporateFactSheet; AmerenIllinois_Form1_2024; UnionElectric_Form1_2024

Additionally, interrogatory A1-03-Staff-292 requests that OPG provide information to support potential expert evidence that may present an alternative annual adjustment mechanism for hydroelectric payment amounts in 2028-2031. Pacific Economics Group Research, LLC (PEG) offers to collaborate with OPG in formulating a response. OEB staff requests that OPG inform OEB staff of issues in responding at the earliest possible time.

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Any questions relating to these interrogatories should be directed to the Case Managers, Thomas Eminowicz, at Thomas.Eminowicz@oeb.ca and Jeffrey Sauer, at Jeffrey.Sauer@oeb.ca. The OEB's toll-free number is 1-888-632-6273.

Yours truly,

Thomas Eminowicz Digitally signed by Thomas Eminowicz Date: 2026.03.25 14:34:56 -04'00'	Jeffrey Sauer Jeffrey Sauer 2026.03.25 14:30:58 -04'00'
Thomas Eminowicz Senior Advisor, Generation & Transmission	Jeffrey Sauer Senior Advisor, Generation & Transmission

OEB Staff Interrogatories (Batch #2)
2027-2031 Payment Amounts Application
Ontario Power Generation (OPG) and DNNP LP
EB-2025-0297
March 25, 2026

Please note, the Applicants are responsible for ensuring that all documents they file with the OEB, including responses to OEB staff interrogatories and any other supporting documentation, do not include personal information (as that phrase is defined in the *Freedom of Information and Protection of Privacy Act*), unless filed in accordance with rule 9A of the OEB's *Rules of Practice and Procedure*.

EXHIBIT A – ADMINISTRATIVE DOCUMENTS

A1-03-Staff-269

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.

A1-03-Staff-270

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.

A1-03-Staff-271

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.

A1-03-Staff-272

Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / pp. 15-17
Ref 2: Exhibit I1 / Tab 2 / Schedule 1 / Table 2
Ref 3: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 3

Preamble:

At Reference 1, OPG describes the proposed stretch factor. The proposal is based on OPG's performance in the econometric analysis conducted by London Economics International, LLC (LEI). One of the details describing the basis for the proposed stretch factor is that capital investments related to plant improvements and expansions are excluded. It is noted that sustaining capital expenditures are considered.

Reference 2 shows, among other things, the capital related revenue requirement from OPG's plan for 2027 to 2031 and the application of the capital stretch factor.

Reference 3 is the cost benchmarking study that forms the basis for the proposed 0.15% stretch factor.

Question(s):

a) Please confirm that it is OPG's proposal for the stretch factor, which is based on Reference 3, to be applied to both the X-Factor reduction and the Capital Stretch Factor. If not confirmed, please explain.
b) If part a) is confirmed, please explain why it is appropriate to use the cost benchmarking study from Reference 3 as the basis for both stretch factors.
c) If part a) is not confirmed, please provide and explain the basis for the Capital Stretch Factor.
d) Please provide a breakdown of the components of the 2027 to 2031 Capital Related Revenue Requirement by providing the break down of the following:
   i. Existing rate base as of the end of 2026
   ii. Sustaining capital investment from 2027 to 2031, as in the context of Reference 3
   iii. Capital investments related to plant improvements and expansions, as in the context of Reference 3
   iv. The sum of any other types of capital related revenue requirement to ensure reconciliation to line 5 of Reference 2
   v. If capital related revenue requirement of sub-part iv) is greater than any of the other sub-parts, please describe and explain that capital work.
e) For part d), sub-part iii) please explain if there are any differences between "capital investments related to plant improvements and expansions" as in Reference 3 and what OPG considers to be CRVA-eligible hydroelectric capital projects.

A1-03-Staff-273

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]					
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.

A1-03-Staff-274

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?

A1-03-Staff-275

Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / Chart 1
Ref 2: Exhibit I1 / Tab 1 / Schedule 1 / Table 1
Ref 3: Exhibit I1 / Tab 2 / Schedule 1 / Table 2

Preamble:

At Reference 1, OPG summarizes the Hydroelectric Custom IR Framework.

Reference 2 provides a breakdown of the 2027 test year revenue requirement.

Reference 3 provides the 2027 revenue requirement with 2028 to 2031 revenue requirements the purpose of calculating the proposed Capital Factor in each of 2028 to 2031.

For the purpose of illustrating the relationship between deferral and variance accounts (DVAs) and Custom IR revenue requirements in each of the years 2027 to 2031, please answer the following questions.

Question(s):

a) Please list all DVAs, either existing or proposed that relate to the capital related revenue requirement due to 2027 to 2031 in-service additions. Further, please provide an annual breakdown of the capital related revenue requirement in each of 2027 to 2031 for the following categories of rate base by completing the following table:
   i. Rate base as at the end of 2026
   ii. In-service additions over the 2027 to 2031 where variances relate to the identified deferral and variance accounts
   iii. In-service additions over the 2027 to 2031 period where no DVA would track and variances.

Table 1: Capital Related Revenue Requirement Details

$ million	2027	2028	2029	2030	2031
For rate base as at the end of 2026					
Cost of Capital					
Short-Term Debt					
Long-Term Debt					
Common Equity					

$ million	2027	2028	2029	2030	2031
Total Cost of Capital					
Depreciation Expense					
Income Tax Expense					
Any other Revenue Requirement Impact					
Total Revenue Requirement Impact relating to rate base as at the end of 2026					
For 2027 to 2031 in-service additions where variances will be tracked in DVAs					
Cost of Capital					
Short-Term Debt					
Long-Term Debt					
Common Equity					
Total Cost of Capital					
Depreciation Expense					
Income Tax Expense					
Any other Revenue Requirement Impact					
Total Revenue Requirement Impact relating to 2027-2031 in-service additions that are captured in DVAs					
For 2027 to 2031 in-service additions where there are no DVAs that would track variances					
Cost of Capital					
Short-Term Debt					
Long-Term Debt					
Common Equity					
Total Cost of Capital					
Depreciation Expense					
Income Tax Expense					
Any other Revenue Requirement Impact					
Total Revenue Requirement Impact relating to 2027-2031 in-service additions where there is no DVA for variances					

b) Please list all DVAs that would track variances to OM&A expenses for 2027 to 2031. Similar to above, please provide a breakdown of those OM&A expenses by completing the following table:

Table 2: OM&A Details

$ million	2027	2028	2029	2030	2031
2027 to 2031 OM&A where variances will be tracked in DVAs					
Base OM&A					
Project OM&A					
Outage OM&A					

$ million	2027	2028	2029	2030	2031
Allocation of Corporate Costs					
Allocation of Centrally Held Costs					
Asset Service Fees					
Any other OM&A Expense where variances are tracked in a DVA					
Total Revenue Requirement Impact from 2027-2031 OM&A Expense that are captured in DVAs					
2027 to 2031 OM&A where there are no DVAs that would track variances					
Base OM&A					
Project OM&A					
Outage OM&A					
Allocation of Corporate Costs					
Allocation of Centrally Held Costs					
Asset Service Fees					
Any other OM&A Expense where there is no DVA to track variances					
Total Revenue Requirement Impact from 2027-2031 OM&A where there is no DVA for variances					

c) Please list all DVAs that would track variances to gross revenue charges (GRC) Expense for 2027 to 2031. Please confirm that it is OPG's proposal that 100% of the GRC Expense would be subject to DVAs. If not confirmed, please complete the following table:

Table 3: Fuel Expense Details

$ million	2027	2028	2029	2030	2031
2027 to 2031 Fuel Expense where variances will be tracked in DVAs					
GRC Expense					
Any other Fuel Expense where variances are tracked in a DVA					
Total Revenue Requirement Impact from 2027-2031 Fuel Expense that are captured in DVAs					
2027 to 2031 Fuel Expense where there are no DVAs that would track variances					
GRC Expense					
Any other Fuel Expense where variances are tracked in a DVA					
Total Revenue Requirement Impact from 2027-2031 Fuel Expense where there is no DVA for variances					

d) Please list all DVAs that would track variances to Property Tax expenses for 2027 to 2031. Similar to above, please provide a breakdown of those Property Tax expenses by completing the following table:

Table 4: Property Tax Details

$ million	2027	2028	2029	2030	2031
Total Revenue Requirement Impact from 2027-2031 Property Tax Expense that are captured in DVAs					
Total Revenue Requirement Impact from 2027-2031 Property Tax Expense where there is no DVA for variances					

e) Please list all DVAs that would track variances to Other Revenues from 2027 to 2031. Similar to above, please provide a breakdown of those Other Revenues by completing the following table:

Table 5: Other Revenue Details

$ million	2027	2028	2029	2030	2031
2027 to 2031 Other Revenue where variances will be tracked in DVAs					
Ancillary Services					
Segregated Mode of Operation					
Water Transactions					
Capacity Exports					
Hydroelectric Incentive Mechanism (HIM) Revenue					
Any additional Other Revenues where variances are tracked in a DVA					
Total Revenue Requirement Impact from 2027-2031 Other Revenues that are captured in DVAs					
2027 to 2031 Property Tax Expense where there are no DVAs that would track variances					
Ancillary Services					
Segregated Mode of Operation					
Water Transactions					
Capacity Exports					
HIM Revenue					
Any additional Other Revenues where there are no DVAs to track variances					
Total Revenue Requirement Impact from 2027-2031 Property Tax Expense where there is no DVA for variances					

f) Please list all DVAs that would track variances to Income Tax expenses from 2027 to 2031 not captured in part a). Similar to above, please provide a breakdown of those Income Tax expenses by completing the following table:

Table 6: Income Tax Expense Details

$ million	2027	2028	2029	2030	2031
Total Revenue Requirement Impact from 2027-2031 Income Tax Expense that are captured in DVAs					
Total Revenue Requirement Impact from 2027-2031 Income Tax Expense where there is no DVA for variances					

A1-03-Staff-276

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
	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

Category	Account	Account Description
	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
Land Structures and Misc	10000100	Hydroelectric - Intangibles
	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.
d) Please repeat parts a) through c) exclusively for CRVA-eligible projects as questions d), e), and f).

A1-03-Staff-277

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.

A1-03-Staff-278

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?

A1-03-Staff-279

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?

A1-03-Staff-280

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-247

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.

A1-03-Staff-281

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.

A1-03-Staff-282

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?

A1-03-Staff-283

Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 3 / Confidential Working Papers
Ref 2: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 3 / pp. 22-25

Preamble:

Most of the data used in London Economics International LLC (LEI)’s benchmarking study are drawn from a proprietary dataset gathered by the Electric Utility Cost Group (EUCG) Hydroelectric Productivity database. LEI is not prepared to share these data with experts for OEB staff and intervenors in this proceeding. Even the names of the peers in the benchmarking studies have not been shared.

At Reference 1, the Applicants redact all data and information save the input price trend indexes. At Reference 2, the Applicants report materially favorable benchmarking results for the Company.

Question(s):

a) Please confirm that it is not possible for OEB staff or intervenor consultants to replicate LEI's benchmarking results using the information provided. If not confirmed, please describe how this would be possible.
b) Do the Applicants believe it is not possible for data, validated or not, to be inadvertently changed, mishandled, or misinterpreted during processing and modeling?
   i. Please provide the Stata code for data processing and model estimation. This has value in the review of this work even if data cannot be provided.
c) PEG may perform its own benchmarking analysis as part of PEG's evidence relating to the stretch factor. It would be useful at a minimum to know the identity of the companies included in the LEI benchmarking work to help explain differences in the results. Please provide a file with the non-EUCG data for each company, plant, and year used in the analysis. It should include the input prices used for each observation and any other data used in the analysis that is not is not covered by the NDA. Please also consider if providing anonymized data would be consistent with the NDA. Although not ideal, it would aid in the testing of at least some aspects of the work.

A1-03-Staff-284

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 <u>not</u> 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?

A1-03-Staff-285

Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 3 / Confidential Working Papers
Ref 2: Exhibit A1 / Tab 3 / Schedule 2 / Attachment 3 / p. 23
Ref 3: EB-2016-0152 / Exhibit L / Tab 11.1 / Schedule 1 / Staff-247

Preamble:

PEG may perform an alternative OPG cost level benchmarking analysis to support potential recommendations relating to the proposed stretch factor. To do so, PEG will require appropriate data from OPG. Where data have already been provided in this filing or publicly available in previous filings, please provide a reference to where the requested data may be found.

Question(s):

a) Please provide the following information *for as many years as the company has data for* up to the present its prescribed hydroelectric generating stations to calculate productivity trends. It is quite useful to have the required capital cost data for a lengthy sample period even if the OM&A expense data aren't available. If there are noteworthy discontinuities in the data, including any revaluations of asset values, please explain them. The OPG response to OEB Staff #247 in EB-2016-0152 can serve as a guide and may contain some of the requested historical data.

   i. Value of gross additions to hydroelectric plant.
   ii. Gross value of hydroelectric plant in service and accumulated depreciation on hydroelectric plant.
   iii. The typical average service life by type of asset that OPG uses to determine depreciation rates for hydroelectric assets. These are not required for each year.
   iv. Total hydroelectric operation, maintenance, and administration (OM&A) expenses by account, itemized by major expenditure category where possible. Please itemize any amounts paid for water for power such that they can be removed as it was in London Economics International LLC's (LEI's) study.
   v. Annual depreciation (amortization) charged for hydroelectric plant.
   vi. Nameplate and operational capacity of each hydroelectric generating station operated by OPG. Please identify which units are conventional and which are pumped storage.
   vii. The total hydroelectric OM&A cost related to compensation of company employees. Should this specific dollar figure be confidential or unavailable, please provide a typical percentage of the total (e.g. "about 60%" based on information over 10 years). Does this amount include the cost of pensions and current employee and other post-employment benefits? If so, approximately what percentage of the total is pension and current and post-employment benefits?
   viii. The weighted average cost of capital, itemized to the extent practicable.

b) To ensure comparability with US data, please provide information regarding the allocation of certain corporate costs to hydroelectric OM&A. For example, Ontario power distributors often fully allocate certain labor costs such as pensions and benefits to non-A&G accounts such as distribution O&M whereas in the US pension and other benefit expenses are recorded in A&G expenses.

c) PEG wishes to develop a plant age and other business condition variables to assist with the benchmarking analysis. To align with available US data, please provide the following information for each hydroelectric facility:
   i. Number of generators and the nameplate capacity of each generator.
   ii. The in-service date for each hydroelectric facility.
   iii. The in-service date for each generator currently in service at each facility. Just the year will be sufficient.
   iv. The mode of each of OPG's hydro plant's operations, from the following categories if possible:
      i. Canal/Conduit
      ii. Intermediate Peaking
      iii. Run-of-river
      iv. Peaking
      v. Reregulating
      vi. Run-of-river/peaking
      vii. Run-of-river/Upstream peaking
   v. Is OPG subject to period license renewal to operate its hydroelectric plants? Are these renewals frequently associated with requests for spending to address environmental or other governmental concerns? Please provide the plant name and year in which any OPG facility has subject to or will be subject to license renewal from 2002-2031.
   vi. OPG is welcome to comment on any other measurable business conditions it faces that it believes have a material impact on cost of operations. Please provide any relevant data that may allow PEG to address such conditions in any benchmarking work it may undertake. Examples might include climate or hydrological conditions.

d) Please provide forecasted values for the following data items for each year for 2025 to 2031. If 2025 actuals are provided in the response to part a of this question, the forecasted data may begin in 2026.
   i. OM&A data consistent with the response to part a of this question.
   ii. Gross plant additions consistent with the response to part a of this question.
   iii. Generation volumes consistent with the response to part a of this question.
   iv. Capacity consistent with the response to part a of this question.

e) In its working papers for the productivity calculations for the monetary approach, the benchmark year for LEI’s capital quantity calculations was 2000. However, on page 2 of Reference 3, OPG stated:

> OPG has determined that data dating earlier than 2002 would not provide a meaningful basis of comparison over time or with peers. Moreover, pre-2002 data is not reconcilable with more recent information, due to changes within OPG’s accounting systems and major changes in the

North American hydroelectric generating industry around the turn of the century. The data provided in this response is from 2002 onward, the same start date used in LEI's TFP study. As noted in Ex. A1-3-2, Attachment 1, p. 16, 2002 is the year that the Ontario competitive electricity market opened, a significant event impacting OPG's business environment. The United States' electricity markets also went through reforms and restructuring phases in the late 1990s and early 2000s. As a result of these changes, data prior to 2002 would not be reconcilable with more recent data, nor would it be representative of OPG or the industry's productivity during the period at issue in this application.

i. Please reconcile LEI's use of a 2000 benchmark year for OPG with the quote from OPG above.
ii. Did OPG revalue its rate base when it was split off from Ontario Hydro? If so, when did that revaluation occur?

A1-03-Staff-286

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?

A1-03-Staff-287

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?

A1-03-Staff-288

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?

A1-03-Staff-289

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?

A1-03-Staff-290

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.

A1-03-Staff-291

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.

A1-03-Staff-292

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.

A1-03-Staff-293

Ref 1: Exhibit A1 / Tab 3 / Schedule 2 / Chart 15
Ref 2: Exhibit I1 / Tab 1 / Schedule 1 / Tables 2 and 2a

Preamble:

At Reference 1, OPG describes the policy objectives of the Nuclear Custom IR Framework. The Framework is a five-year cost of service application with a proposed stretch factor reduction. The summary states that operational effectiveness, outcomes & performance measurement, customer focus, and protecting customers are the policy objectives.

The two tables that are Reference 2 detail the OPG Nuclear and DNNP Revenue Requirements for 2027-2031. The Revenue Requirements before the application of stretch factor are the sum of five general categories. These are: the Cost of Capital; the sum of the OM&A, Fuel, Depreciation & Amortization, and Property Tax Expenses; less Other Revenues; Concurrent Cost Recovery Costs; and Income Tax Expense. The cumulative OPG Nuclear and DNNP Facilities Revenue Requirement, before stretch factor and without the impact of payment amount riders, is $26,588 million.

The two tables that are Reference 2 are summarized as follows:

Table 1: Sum of OPG Nuclear and DNNP Revenue Requirements 2027-2031

#	$ million	OPG Nuclear	DNNP	sum
1	Total Cost of Capital	6,264	720	6,984
2	OM&A	9,547	678	10,225
3	Fuel	1,164	104	1,267
4	Depreciation & Amortization	3,875	132	4,007
5	Property Tax	72	5	77
6	Bruce Lease Revenues Net of Direct Costs	(22)		(22)
7	Ancillary and Other Revenue	90		90
8	Concurrent Cost Recovery - Pickering Refurbishment Program	2,923		2,923
9	Concurrent Cost Recovery - DNNP		1,120	1,120
10	Income Tax	(83)	-	(83)
Lines 1 + 2 + 3 + 4 + 5 - 6 - 7 + 8 + 9 + 10			Total, 2027 to 2031:	26,451

Question(s):

a) Please confirm the values in the above table. If not confirmed, please correct any erroneous transcription errors and reference the corrected amounts in the responses to this interrogatory. Please ensure reconciliation to the above / corrected table and explain any additional details for that reconciliation.

b) Please list all deferral and variance accounts (DVAs), either existing or proposed, that relate to the capital related revenue requirement due to 2027 to 2031 in-service additions. Further, please provide an annual breakdown of the capital-related revenue requirement in each of 2027 to 2031 for the following categories of rate base by completing the following table:

i. Rate base as at the end of 2026

ii. In-service additions over the 2027 to 2031 period where variances would be tracked by a deferral or variance account.

iii. In-service additions over the 2027 to 2031 period where no deferral or variance account would track variances.

Table 2: Capital Related Revenue Requirement Details

$ million	2027	2028	2029	2030	2031
i. For rate base as at the end of 2026					
Cost of Capital					
Short-Term Debt					
Long-Term Debt					
Common Equity					

$ million	2027	2028	2029	2030	2031
EB-2020-0290 Settlement Adjustment for Equity at Long-Term Debt Rate					
Adjustment for Lesser of Unfunded Nuclear Liabilities (UNL) or Asset Retirement Cost (ARC)					
Total Cost of Capital					
Depreciation Expense					
Income Tax Expense					
Any other Revenue Requirement Impact					
Total Revenue Requirement Impact relating to rate base as at the end of 2026					
ii. For 2027 to 2031 in-service additions where variances will be tracked in DVAs					
Cost of Capital					
Short-Term Debt					
Long-Term Debt					
Common Equity					
Adjustment for Lesser of UNL or ARC					
Total Cost of Capital					
Depreciation Expense					
Income Tax Expense					
Any other Revenue Requirement Impact					
Total Revenue Requirement Impact relating to 2027-2031 in-service additions that are captured in DVAs					
iii. For 2027 to 2031 in-service additions where there are no deferral or variance accounts that would track variances					
Cost of Capital					
Short-Term Debt					
Long-Term Debt					
Common Equity					
Adjustment for Lesser of UNL or ARC					
Total Cost of Capital					
Depreciation Expense					
Income Tax Expense					
Any other Revenue Requirement Impact					
Total Revenue Requirement Impact relating to 2027-2031 in-service additions where there is no DVA for variances					

a) Please list all DVAs that would track variances to OM&A expenses from 2027 to 2031. Similar to above, please provide a breakdown of those OM&A expenses for which variances would be tracked by a DVA, and of those which would not tracked by a DVA, by completing the following table:

Table 3: OM&A Details

$ million	2027	2028	2029	2030	2031
2027 to 2031 OM&A where variances will be tracked in DVAs					
Nuclear Facilities Base OM&A					
Nuclear Facilities Project OM&A					
Nuclear Facilities Outage OM&A					
Pickering Cyclical Maintenance OM&A					
DNNP Operational Readiness					
Allocation of Corporate Costs					
Allocation of Centrally Held Costs					
Asset Service Fees					
Any other OM&A Expense where variances are tracked in a DVA					
Total Revenue Requirement Impact from 2027-2031 OM&A Expenses that are captured in DVAs					
2027 to 2031 OM&A where there are no DVAs that would track variances					
Nuclear Facilities Base OM&A					
Nuclear Facilities Project OM&A					
Nuclear Facilities Outage OM&A					
Pickering Cyclical Maintenance OM&A					
DNNP Operational Readiness					
Allocation of Corporate Costs					
Allocation of Centrally Held Costs					
Asset Service Fees					
Any other OM&A Expense where there is no deferral or variance account to track variances					
Total Revenue Requirement Impact from 2027-2031 OM&A where there is no DVA for variances					

b) Please list all DVAs that would track variances to Nuclear Fuel expenses from 2027 to 2031. Similar to above, please provide a breakdown of those Fuel expenses by completing the following table:

Table 4: Fuel Expense Details

$ million	2027	2028	2029	2030	2031
2027 to 2031 Fuel Expense where variances will be tracked in DVAs					
Canada Deuterium Uranium (CANDU) Fuel Costs					
Small Modular Reactor (SMR) Fuel Costs					
Any other Fuel Expense where variances are tracked in a DVA					

$ million	2027	2028	2029	2030	2031
Total Revenue Requirement Impact from 2027-2031 Fuel Expense that are captured in DVAs					
2027 to 2031 Fuel Expense where there are no DVAs that would track variances					
CANDU Fuel Costs					
SMR Fuel Costs					
Any other Fuel Expense where variances are tracked in a DVA					
Total Revenue Requirement Impact from 2027-2031 Fuel Expense where there is no DVA for variances					

c) Please list all DVAs that would track variances to Property Tax expenses from 2027 to 2031. Similar to above, please provide a breakdown of those Property Tax expenses by completing the following table:

Table 5: Property Tax Details

$ million	2027	2028	2029	2030	2031
2027 to 2031 Property Tax Expense where variances will be tracked in DVAs					
Darlington Nuclear Generating Station (NGS)					
Pickering NGS					
DNNP Facilities					
Any other Property Tax Expense where variances are tracked in a DVA					
Total Revenue Requirement Impact from 2027-2031 Property Tax Expense that are captured in DVAs					
2027 to 2031 Property Tax Expense where there are no DVAs that would track variances					
Darlington NGS					
Pickering NGS					
DNNP Facilities					
Any other Property Tax Expense where there are no variance accounts to track variances					
Total Revenue Requirement Impact from 2027-2031 Property Tax Expense where there is no DVA for variances					

d) Please list all DVAs that would track variances to Other Revenues from 2027 to 2031. Similar to above, please provide a breakdown of those Other Revenues by completing the following table:

Table 6: Other Revenue Details

$ million	2027	2028	2029	2030	2031

$ million	2027	2028	2029	2030	2031
2027 to 2031 Other Revenue where variances will be tracked in DVAs					
Bruce Lease Revenues					
Bruce Lease Costs					
Non-Energy Revenues					
Non-Energy Direct Costs					
Ancillary Services					
Any additional Other Revenues where variances are tracked in a DVA					
Total Revenue Requirement Impact from 2027-2031 Other Revenues that are captured in DVAs					
2027 to 2031 Other Revenues where there are no DVAs that would track variances					
Bruce Lease Revenues					
Bruce Lease Costs					
Non-Energy Revenues					
Non-Energy Direct Costs					
Ancillary Services					
Any additional Other Revenues where there are no deferral or variance accounts to track variances					
Total Revenue Requirement Impact from 2027-2031 Property Tax Expense where there is no DVA for variances					

e) Please list all DVAs that would track variances to Concurrent Cost Recovery Expenses from 2027 to 2031. Please confirm that 100% of the Concurrent Cost Recovery Expenses from 2027 to 2031 will be subject to deferral or variance account treatment. If not confirmed, please complete the following table:

Table 7: Concurrent Cost Recovery Details

$ million	2027	2028	2029	2030	2031
2027 to 2031 Concurrent Cost Recovery Expenses where variances will be tracked in DVAs					
Pickering Refurbishment Concurrent Cost Recovery					
DNNP Concurrent Cost Recovery					
Total Revenue Requirement Impact from 2027-2031 Concurrent Cost Recovery that are captured in DVAs					
2027 to 2031 Concurrent Cost Recovery Expense where there are no DVAs that would track variances					
Pickering Refurbishment Concurrent Cost Recovery					
DNNP Concurrent Cost Recovery					

$ million	2027	2028	2029	2030	2031
Total Revenue Requirement Impact from 2027-2031 Concurrent Cost Recovery Expense where there is no DVA for variances					

f) Please list all DVAs that would track variances to Income Tax expenses from 2027 to 2031 not captured in part a). Similar to above, please provide a breakdown of those Income Tax expenses by completing the following table:

Table 8: Income Tax Expense Details

$ million	2027	2028	2029	2030	2031
Total Revenue Requirement Impact from 2027-2031 Income Tax Expense that are captured in DVAs					
Total Revenue Requirement Impact from 2027-2031 Income Tax Expense where there is no DVA for variances					

A1-03-Staff-294

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.

A1-03-Staff-295

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.

A1-03-Staff-296

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.

A1-03-Staff-297

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.

EXHIBIT C – CAPITALIZATION, COST OF CAPITAL AND NUCLEAR LIABILITIES

C1-01-Staff-298

Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 14, 66, 67, 72, 73, 74, 75, 103-109
Ref 2: Excel file "Authorized Equity Ratio Analysis Workpaper – PUBLIC"
Ref 3: Excel file "Proxy Group Screening Workpaper – PUBLIC"
Ref 4: Excel file "Actual Equity Ratio Analysis Workpaper – PUBLIC"

Preamble:

Concentric included the following figures in its report which are summarized in Table 1 below by OEB staff.

Table 1 – Summary of Concentric's Figures of Peer Groups

Figure No.	Figure Name	Figure Description
1	Summary Statistics for Peer Groups	Shows a graph of some of the data included in Figure 16.
15	Concentric Peer Groups	Shows the utilities in the Main Proxy Group, Nuclear Group, and Hydro Group
16	Summary of Peer Group Analysis	Shows the actual and authorized capital structures (mean and median) for the Main Proxy Group, Nuclear Group, and Hydro Group.
17	Fair Return Standard Analyses of Equity Ratios	Shows a graph of some of the data included in Figure 16.
21	Concentric Proxy Group Equity Ratios	Shows the holding companies 5-year average actual capital structures % and average authorized capital structures %
23	Equity Ratios – Concentric Proxy Group vs. "Most Credit Supportive" Jurisdictions	Shows the mean, median, minimum, and maximum authorized capital structures for the Main Proxy Group and the Most Credit Supportive Group
24	FRS Analysis of Equity Ratios – Concentric and "Most Credit Supportive" Proxy Groups	Shows a graph of some of the data included in Figure 23

At footnote 145, Concentric stated the following:

> Figure 23 illustrates only the subset of "most credit supportive" jurisdictions as a result of a screening process of the main Concentric Proxy Group. In the U.S., the resulting states were Michigan, Kentucky, Florida, Alabama, and Wisconsin. In Canada, only British Columbia passed the screen…

In the first above noted Excel file, tab "Authorized Equity Ratios", column J describes the level of S&P credit supportiveness. The other above noted Excel files do not address the level of S&P credit supportiveness.

OEB staff notes that the questions are directed to Concentric.

Question(s):

a) Please confirm that “Table 1 – Summary of Concentric’s Figures of Peer Groups” is accurate. Please update the table as applicable and explain any changes made.
b) Please explain why Figure 23 and Figure 24 illustrate only a subset of most credit supportive jurisdictions, as a result of Concentric’s screening process of the Main Proxy Group, as opposed to all credit supportive jurisdictions.
c) Please explain why the utilities in the Most Credit Supportive Jurisdictions Proxy Group are not listed in the following Excel files, as well as the figures in “Table 1 – Summary of Concentric’s Figures of Peer Groups”, and pages 103-109 of the Concentric report:
    i. Excel file “Authorized Equity Ratio Analysis Workpaper – PUBLIC”, tab “Authorized Equity Ratios” and tab “Holding Company Averages”
    ii. Excel file “Proxy Group Screening Workpaper – PUBLIC”, tab “Proxy Group Screen” and tab “Final Proxy Groups”
    iii. Excel file “Actual Equity Ratio Analysis Workpaper – PUBLIC”, tab “Summary Holdcos” and tab “Proxy Group”
d) Please update the references and analysis included in part c) of this question to include the utilities in the separate grouping for the Most Credit Supportive Jurisdictions Proxy Group.

C1-01-Staff-299

Ref 1: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 14, 66, 67, 72, 73, 74, 75, 103-109
Ref 2: Excel file “Authorized Equity Ratio Analysis Workpaper – PUBLIC”
Ref 3: Excel file “Proxy Group Screening Workpaper – PUBLIC”
Ref 4: Excel file “Actual Equity Ratio Analysis Workpaper – PUBLIC”

Preamble:

In the interrogatories below OEB staff has asked questions about the following utilities:

- NextEra and Florida Power & Light Co
- Dominion Resources, Virginia Electric and Power Company, Dominion Energy South Carolina, Dominion Energy’s subsidiary in Virginia
- Ameren Corporation, Union Electric Company, Ameren Illinois Company

- Algonquin Power & Utilities Corporation, Liberty Utilities (CalPeco Electric) LLC, Liberty Utilities (Granite State Electric) Corp., The Empire District Electric Company
- Emera Inc. and Tampa Electric Company
- Fortis Inc., Central Hudson Gas & Electric Corp., Tucson Electric Power Company, and UNS Electric, Inc.

OEB staff notes that the questions are directed to Concentric.

Question(s):

a) Based on the questions below asked by OEB staff, please explain whether the authorized and/or actual capital structure values related to each of the above-noted utilities should be omitted from:
   i. The figures in OEB staff's "Table 1 – Summary of Concentric's Figures of Peer Groups"
   ii. The related Excel files described in question C1-01-Staff-298 part c), and
   iii. Pages 103-109 of Concentric's report

C1-01-Staff-300

Ref 1: Excel file "Authorized Equity Ratio Analysis Workpaper – PUBLIC"
Ref 2: Exhibit C / Tab 1 / Schedule 1 / Attachment 1 / pp. 62-67

Preamble:

The Concentric Report states:

> In addition to the Concentric Proxy Group, a secondary screen for companies with a minimum threshold of nuclear capacity (i.e., 5% or more MW capacity) was conducted to form the Nuclear Group. This group comprised of a subset of 12 U.S. utilities from the Concentric Proxy Group. Finally, to reflect the risk inherent in OPG's hydroelectric generation operations, Concentric created another subset of the Concentric Proxy Group that screened for a minimum threshold of hydroelectric capacity (i.e., 5% or more MW capacity). (p. 65)

OEB staff notes that the questions are directed to Concentric.

Question(s):

a) How was five percent chosen as a threshold nuclear and hydroelectric generation in selecting the peer groups?

C1-01-Staff-301

Ref 1: Excel file “Authorized Equity Ratio Analysis Workpaper – PUBLIC”
Ref 2: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 62-72

Preamble:

Referring to Excel file “Authorized Equity Ratio Analysis Workpaper – PUBLIC”, Cell Y3 on sheet “Past Rate Cases” reads: “The following states were excluded due to inclusion of zero-cost of capital items in equity ratio authorization.” Florida is included on this list of excluded jurisdictions.

However, cell Y438 contains a manually entered number for Florida Power & Light, which conducts business as NextEra. A comment on this cell reads: “Manually added. Internal Concentric Data.”

NextEra (NEE) is included in the “Main Peer Group” and “Nuclear Group” found in Figure 15, as well as the list of proxy group equity ratios found in Figure 21.

OEB staff notes that the questions are directed to Concentric.

Question(s):

a) Should NextEra be excluded from the analysis, per the note found in Cell Y3?
b) If NextEra should be included in the analysis, why does the note in Cell Y3 not apply in this instance?
c) If NextEra should be excluded for the reason stated in Cell Y3, should NextEra’s capital structure be omitted from the values found in Figure 16 (p. 67), and from the “Max” row in Report Figure 23 (p.75), and the “Group Max” in Report Figure 24 (p. 75)?
d) Please provide an update to Figure 16 with NextEra excluded from the sample.
e) Please provide an update to Figure 17 with NextEra excluded from the sample.

C1-01-Staff-302

Ref 1: Excel file "Authorized Equity Ratio Analysis Workpaper – PUBLIC"
Ref 2: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 62-72, 106
Ref 3: Attachment 1, RiderGEN_capitalstructure_testimony_2024
Ref 4: Attachment 2, RiderGEN_Decision_2025

Preamble:

Referring to Excel file "Authorized Equity Ratio Analysis Workpaper – PUBLIC", sheet "Authorized Equity Ratios", rows 20 and 21 contain data for two subsidiaries of Dominion Energy: Virginia Electric and Power Company's operations in North Carolina and Dominion Energy South Carolina's operations in South Carolina.

Dominion Resources (D) is included in the "Main Peer Group" and "Nuclear Group" found in Figure 15, as well as the list of proxy group equity ratios found in Figure 21.

Also, Dominion Energy in Virginia has an authorized capital structure specifically applied to the company's generation assets (see attachments "RiderGEN_capitalstructure_testimony_2024" and "RiderGEN_Decision_2025"). This capital structure is set by the Virginia Corporation Commission through a proceeding to determine the parameters for a rate rider called "Rider GEN" for Dominion Energy's Virginia operations. Dominion Energy's subsidiary in Virginia was not included in the analysis, according to sheet "Authorized Equity Ratios" in Excel file "Authorized Equity Ratio Analysis Workpaper – PUBLIC."

OEB staff notes that the questions are directed to Concentric.

Question(s):

a) Does the data in row 20, associated with Virginia Electric and Power Company, labeled "North Carolina" in cell C20, reflect operations of Virginia Electric and Power Company only in North Carolina (and not in Virginia)?
b) If Dominion Energy's operations in Virginia are not included in this analysis, why?
c) Does Virginia Electric and Power Company have any nuclear assets in North Carolina?

d) If not, should Dominion Energy's approved capital structure in North Carolina be included in the "nuclear" proxy group if the company's nuclear operations are not in North Carolina?
e) Please provide an update to Figure 16 with Dominion Energy's North Carolina subsidiary excluded from the sample.
f) Please provide an update to Figure 17 with Dominion Energy's North Carolina subsidiary excluded from the sample.
g) Why was the capital structure for generation assets in Dominion's Virginia subsidiary, as identified by "Rider GEN," excluded from the analysis?
h) Please provide an update to Figure 16 with the Rider GEN capital structure included in the sample.
i) Please provide an update to Figure 17 with the Rider GEN capital structure included in the sample.

C1-01-Staff-303

Ref 1: Excel file "Authorized Equity Ratio Analysis Workpaper – PUBLIC"
Ref 2: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 62-67
Ref 3: Attachment 3, AmerenCorporateFactSheet
Ref 4: Attachment 4, AmerenIllinois_Form1_2024
Ref 5: Attachment 5, UnionElectric_Form1_2024

Preamble:

According to page 1 of Ameren Illinois's "Corporate Facts" ("AmerenCorporateFactSheet," attached): "Ameren Illinois is a delivery-only utility." Plant in Service data from Ameren Illinois's FERC Form 1 for 2024 (p. 204-207 and p. 406-411 of "AmerenIllinois_Form1_2024," attached) indicates that Ameren Illinois does not own substantial generation plant. In particular, Ameren Illinois reports only one generating plant, a solar facility called East St. Louis Solar Energy Center, which has a Net Peak Demand of 1.5 MW.

Union Electric Company does own generation plant (see "UnionElectric_Form1_2024," attached).

Referring to Excel file "Authorized Equity Ratio Analysis Workpaper – PUBLIC", sheet "Authorized Equity Ratios", row 5 contains data for Ameren Illinois Company. The analysis uses the authorized capital structure for Ameren Illinois (50% equity) to represent the entirety of Ameren Corporation, but does not use the authorized capital structure for Union Electric Company.

Ameren Corporation is included in the “Main Peer Group” and the “Nuclear Group” in Figure 15, as well as the list of proxy group equity ratios found in Figure 21.

OEB staff notes that the questions are directed to Concentric.

Question(s):

a) Why should the analysis include Ameren Corporation if an authorized capital structure is not available for the subsidiary (Union Electric Company) that owns generation plant?
b) If Ameren Corporation should be included in the proxy group, why should Ameren Illinois, which does not own substantial generation plant, serve as the sole data point for Ameren Corporation’s authorized capital structure?
c) Please provide an update to Figure 16 with Ameren Corporation excluded from the sample.
d) Please provide an update to Figure 17 with Ameren Corporation excluded from the sample.

C1-01-Staff-304

Ref 1: Excel file “Actual Equity Ratio Analysis Workpaper – PUBLIC”
Ref 2: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 62-67

Preamble:

Concentric included Algonquin Power & Utilities Corporation in the study sample “[i]n order to broaden the proxy group to include at least a minimal number of Canadian utilities” (p. 65). However, the three subsidiaries of Algonquin in the sample are Liberty Utilities (CalPeco Electric) LLC, Liberty Utilities (Granite State Electric) Corp., and The Empire District Electric Company.

Algonquin Power & Utilities Corporation (AQN) is included in the “Main Peer Group” found in Figure 15, as well as the list of proxy group equity ratios found in Figure 21.

OEB staff notes that the questions are directed to Concentric.

Question(s):

a) Do any of the three Algonquin subsidiaries used in the study sample conduct any operations in Canada?
b) If not, should this company be excluded from the analysis, since it fails two of Concentric's screens and no data is used based on subsidiaries in Canada?
c) Please provide an update to Figure 16 with Algonquin excluded from the sample.
d) Please provide an update to Figure 17 with Algonquin excluded from the sample.

C1-01-Staff-305

Ref 1: Excel file "Actual Equity Ratio Analysis Workpaper – PUBLIC"
Ref 2: Excel file "Authorized Equity Ratio Analysis Workpaper – PUBLIC"
Ref 3: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 62-67

Preamble:

Concentric included Emera Inc. in the study sample "In order to broaden the proxy group to include at least a minimal number of Canadian utilities." (p. 65) However, the Emera subsidiary Tampa Electric Company operates in Florida.

Referring to Excel file "Authorized Equity Ratio Analysis Workpaper – PUBLIC", Cell Y3 on sheet "Past Rate Cases" reads: "The following states were excluded due to inclusion of zero-cost of capital items in equity ratio authorization." Florida was included in this list of states.

Emera (EMA) is included in the "Main Peer Group" found in Figure 15, as well as the list of proxy group equity ratios found in Figure 21.

OEB staff notes that the questions are directed to Concentric.

Question(s):

a) Should Tampa Electric Company be included in the sample, if it is not a Canadian utility and fails the other screening tests?

b) Should Tampa Electric Company be included in the sample, in light of the note on Cell Y3 in Excel “Authorized Equity Ratio Analysis Workpaper – PUBLIC”, sheet “Past Rate Cases”?
c) Please provide an update to Figure 16 with Tampa Electric Company excluded from the sample.
d) Please provide an update to Figure 17 with Tampa Electric Company excluded from the sample.

C1-Staff-306

Ref 1: Excel file “Actual Equity Ratio Analysis Workpaper – PUBLIC”
Ref 2: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 62-67

Preamble:

Concentric included Fortis in the study sample “[i]n order to broaden the proxy group to include at least a minimal number of Canadian utilities” (p. 65). However, the Fortis subsidiaries UNS Electric, Inc., Central Hudson Gas & Electric, and Tucson Electric Power Company do not appear to operate in Canada.

Fortis Inc. (FTS) is included in the “Main Peer Group” found in Figure 15, as well as the list of proxy group equity ratios found in Figure 21.

OEB staff notes that the questions are directed to Concentric.

Question(s):

a) Should UNS Electric, Inc., Central Hudson Gas & Electric and Tucson Electric Power Company (subsidiaries of Fortis, Inc.) be included in the analysis?
b) Please provide an update to Figure 16 with UNS Electric, Inc., Central Hudson Gas & Electric, and Tucson Electric Power Company excluded from the sample.
c) Please provide an update to Figure 17 with UNS Electric, Inc., Central Hudson Gas & Electric, and Tucson Electric Power Company excluded from the sample.

C1-Staff-307

Ref 1: Excel file "CEA Exhibits - Proxy Group Screening Workpaper – PUBLIC"
Ref 2: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 29-33 and 62-67
Ref 3: Excel file "CEA Fig 9 Peer CapEx Workpaper"

Preamble:

On page 29, Concentric cites OPG's projected increase in capital spending as a source of increased risk: "Other than the shifting generation mix for OPG, the most important change in business risk for OPG as compared to 2020 and 2016 is the magnitude of the Company's planned capital expenditure ("CapEx") program over the upcoming rate period from." (sic)

OEB staff notes that the questions are directed to Concentric.

Question(s):

a) Did Concentric consider screening utilities for the proxy groups based on projected CapEx growth? Why or why not?

C1-Staff-308

Ref 1: Excel file "CEA Exhibits - Proxy Group Screening Workpaper – PUBLIC"
Ref 2: Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 62-67

Preamble:
The sheet "Proxy Group Screen" contains several criteria that Concentric used to screen companies for a proxy group with characteristics similar to OPG. In order to be included in the proxy group, companies must obtain 60% of revenue and 60% of net income from regulated activities. In addition, companies must obtain 80 percent of revenue and net income from electricity sales.

OEB staff notes that the questions are directed to Concentric.

Question(s):

a) What percentage of OPG's revenues and net income are from regulated activities?
b) How was the use of 80 percent as the threshold for electricity-related revenue and net income selected?
c) How was the use of 60% as the threshold for regulated related revenue and net income selected?
d) Why is there no minimum threshold for generation plant?
e) Why is there no minimum threshold for nuclear generation?
f) Why is there no minimum threshold for hydroelectric generation?

EXHIBIT D – CAPITAL PROJECTS

D1-01-Staff-309

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 01 / 80581
Ref 2: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 11 / 83148
Ref 3: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 22 / 86364
Ref 4: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 30 / 86793
Ref 5: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 24 / 86386

Preamble:

At the referenced filings, OPG states that the proposed projects are required to address asset condition, reliability, obsolescence, or failure risk. The questions below explore the underlying technical evidence, the basis for the timing of intervention, and the extent to which the preferred scope is limited to the minimum work required to address the identified need.

Question(s):

a) For each referenced project, please identify the specific condition assessments, inspection reports, engineering analyses, remaining-life evaluations, original equipment manufacturers (OEM) studies, or risk assessments relied upon to justify the proposed work.
b) For the above projects, please provide a summary distinguishing between:
   i. Scope required to address the identified asset-condition, reliability, safety, or obsolescence issue

   ii. Scope that provides additional performance, efficiency, maintainability, or life-extension benefit beyond the minimum required corrective scope

c) For each project, please describe the repair, targeted replacement, reduced-scope, staged, or deferral alternatives considered, including any "delay work" alternative and explain why those alternatives were not selected.
d) Please explain how OPG used decision matrices, engineering options analysis, or other tools to select the preferred alternative and scope for these projects.

D1-01-Staff-310

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 05 / 82087
Ref 2: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 14 / 83194
Ref 3: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 24 / 86386
Ref 4: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 25 / 86387

Preamble:

For the referenced projects, OPG proposes major redevelopment, replacement, or large-scale rehabilitation work, in some cases with associated capacity or energy gains, while the filings also reference decommissioning, base-case, or narrower-scope alternatives. The record does not consistently show the technical and economic basis for selecting the preferred alternative over lower-cost or lower-scope options.

Question(s):

a) For each referenced project, please explain the technical basis for selecting the preferred redevelopment / replacement alternative rather than repair, rehabilitation, staged intervention, or decommissioning.
b) Please provide the principal assumptions used in the alternative comparisons, including asset-condition assumptions, service-life assumptions, generation / energy benefits, outage assumptions, and cost-estimate maturity by alternative.
c) Please explain the extent to which expected capacity increases, energy gains, or strategic benefits influenced OPG's choice of the preferred alternative and how those benefits were weighed against lower-cost alternatives.
d) Please identify any decision thresholds, engineering criteria, or economic criteria used to conclude that the preferred alternatives are prudent.

D1-01-Staff-311

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 23 / 86372
Ref 2: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 26 / 86570
Ref 3: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 29 / 86792
Ref 4: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 37 / 87356
Ref 5: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 38 / 87357
Ref 6: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 39 / 87362
Ref 7: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 41 / 87768
Ref 8: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 27 / 86587
Ref 9: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 32 / 86937

Preamble:

Across the referenced turbine-generator refurbishment projects, OPG identifies similar need drivers and similar major scope elements. The questions below explore the common decision framework used to determine refurbishment timing and scope, the extent of repeat engineering or standardization across the portfolio, and the prudence basis for committing to major procurement or engineering work at relatively early gate stages.

Question(s):

a) Please explain the decision framework or criteria used by OPG to determine when a hydroelectric unit proceeds to major refurbishment rather than continued maintenance, targeted repair, or narrower-scope intervention.
b) For each referenced project, please explain how OPG determined the timing and scope of refurbishment, including turbine, generator, governor, controls, electrical, and associated balance-of-plant scope.
c) Please explain the extent to which OPG has standardized technical specifications, design basis, procurement strategy, repeat engineering, or execution approach across these projects, and quantify any expected cost, schedule, or execution benefits from that approach.
d) Where the filing contemplates procurement of long-lead equipment or significant original equipment manufacturers (OEM) / engineering commitments before total project cost and execution scope are fully established, please explain why that level of commitment is prudent at the current gate and what controls are in place to prevent premature scope lock-in.

D1-01-Staff-312

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 33 / 87142
Ref 2: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 35 / 87217
Ref 3: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 40 / 87575
Ref 4: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 43 / 89354
Ref 5: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 28 / 86595
Ref 6: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 39 / 87362
Ref 7: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 42 / 89252

Preamble:

For the referenced projects, OPG describes the underlying need as urgent, high-priority, or significant from a reliability, safety, or dam-risk perspective, while the corresponding implementation timelines extend over multiple years. The questions below explore the relationship between these projects' urgency and their multi-year implementation timelines.

Question(s):

a) For each referenced project, please explain why the project is characterized as urgent or high priority if the implementation timeline extends over several years.
b) Please identify the interim inspection, monitoring, temporary repair, operational restriction, contingency planning, or other mitigation measures that will be used to manage the identified risks until the projects are completed.
c) Please explain whether acceleration or narrower interim mitigation alternatives were considered and, if so, why they were not selected.
d) Please explain how the above projects were prioritized relative to other hydroelectric capital projects addressing comparable condition, reliability, or dam-safety risks.

D1-01-Staff-313

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 8 / 82542
Ref 3: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 26 / 86570
Ref 4: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 27 / 86587

Ref 5: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 30 / 86793
Ref 6: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 32 / 86937

Preamble:

For the referenced projects, the filing indicates that capital refurbishment work is being planned or executed together with overhaul, maintenance, or other non-capital work during a common outage or bundled execution strategy. The questions below explore how scope, schedule, and cost have been separated between capital and OM&A treatment.

Question(s):

a) For the above projects, please explain the portion of the work that is treated as capital versus OM&A or overhaul, and explain the basis for that classification.
b) Please explain how OPG separated shared costs, including project management, outage support, disassembly, inspections, contractor mobilization, scaffolding, cranage, temporary works, testing, and commissioning support, between capital and OM&A treatment.
c) For the above projects, please identify any work that is being executed concurrently for efficiency but is not required for the capital scope and explain how that work was excluded from the capital budget.
d) Please provide any allocation methodology, cost-splitting logic, or accounting guidance applied to support the proposed treatment.

D1-01-Staff-314

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 7 / 82391

Preamble:

For Project 82391 Alexander G1 Capital Refurb, the filing shows a Definition phase project with current-release commitments. The questions below are aimed at understanding the basis for the proposed scope, schedule assumptions, and prudence of the current release.

Question(s):

a) Please provide the most recently approved Business Case Summary (BCS) for Project 82391, if applicable.
b) If no updated approved BCS is available, please explain the basis for the current total project cost estimate, including the principal scope, engineering, procurement, outage, and schedule assumptions on which the estimate is based.
c) Please explain which elements of the proposed scope are required to address the identified asset condition or reliability need, and which elements provide additional performance, efficiency or life- extension benefits.
d) Please explain why the level of engineering and procurement commitment proposed at the current gate is prudent.

D1-01-Staff-315

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 16 / 83833

Preamble:

For Project 83833 Surge Tank Replacement, OPG states that the surge tank is approaching end of service life and that replacement is required. Reference 1 states that OPG relied on a prior condition assessment, which OEB staff was unable to locate in the pre-filed evidence.

Question(s):

a) Please provide the condition assessment or engineering evaluation relied upon for Project 83833, including the deterioration mechanisms identified, remaining-life conclusions, repairability assessment, and basis for concluding that replacement is required.
b) Please identify the principal technical and execution uncertainties remaining at the current project stage and explain how those uncertainties are reflected in estimate maturity, contingency, and the proposed execution strategy.
c) Please provide a cost breakdown for the preferred alternative by major work category and identify the principal cost drivers.

D1-01-Staff-316

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 2 / 80583
Ref 2: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 3 / 80649
Ref 3: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 6 / 82089
Ref 4: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 9 / 82543
Ref 5: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 10 / 82777
Ref 6: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 15 / 83495
Ref 7: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 19 / 84494
Ref 8: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 21 / 84907

Preamble:

For the referenced superseding and recovery projects, OPG seeks additional funding and/or revised timing following discovery work, schedule extension, commissioning problems, equipment failure, or other execution issues.

Question(s):

a) For each referenced project, please provide a summary of changes from the last approved baseline schedule to the current request showing, for each major milestone, the original date, revised date, variance, and principal cause of variance.
b) For each referenced project, please provide a summary of cost changes by major category showing the original approved cost, incremental cost incurred to date, the currently requested increment, and the remaining cost to complete.
c) Please describe the key factors contributing to the material schedule and cost variances for each project including discovery work, design immaturity, contractor-role changes, procurement delay, manufacturing or delivery issues, extended commissioning, equipment failure, owner-support growth, or other project-specific drivers, as applicable.
d) Where equipment failure, commissioning problems, or recovery work occurred, please summarize the documented root cause, corrective action, and allocation of cost responsibility among OPG, original equipment manufacturers (OEMs), contractors, and other counterparties.
e) Please identify any remaining commercial exposure, claims, unresolved contractor issues, or residual contingency at the time of the current filing.

D1-01-Staff-317

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 5 / 82087
Ref 2: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 14 / 83194
Ref 3: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 24 / 86386
Ref 4: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 25 / 86387
Ref 5: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 27 / 86587
Ref 6: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 31 / 86860
Ref 7: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 42 / 89252
Ref 8: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 44 / 89505

Preamble:

Across the referenced projects, the filings provide milestone tables and high-level schedule information, in several cases the basis for the filed completion date, key sequencing assumptions and major schedule dependencies are not fully explained.

Question(s):

a) For each referenced project, please explain the principal assumptions supporting the filed completion date, including major permitting, procurement, work-window, outage or sequencing dependencies, as applicable.
b) Where milestone sequences appear difficult to reconcile, please explain the sequencing logic relied upon by OPG and identify any key assumptions regarding design completion, procurement, outage timing, access or construction staging.
c) For projects with multi-season or long-duration execution programs, please identify the major work planned in each principal execution stage or season and explain why the overall duration is reasonable.

D1-01-Staff-318

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 24 / 86386

Preamble:

In Reference 1, OPG provides the Business Case Summary (BCS) for the Kakabeka Falls GS Redevelopment project. The BCS states that the turbine-generator units were assessed in 2021 and that the remaining useful life of the equipment is estimated to be approximately five years. The BCS also indicates that the project remains at a Class 3 cost estimate and that Indigenous and stakeholder engagement activities are anticipated to occur in later stages of the project.

The BCS indicates that redevelopment is required to address aging infrastructure and long-term operational risks associated with the existing facility. OEB staff was unable to locate detailed findings of the turbine-generator condition assessment or the condition of other major assets associated with the redevelopment, including the penstock and hydraulic structures.

The questions below explore the asset condition assessments supporting the project need, the maturity of the project cost estimate, the timing of stakeholder engagement, and the monitoring and management of hydraulic and public safety risks associated with the existing infrastructure prior to redevelopment.

Question(s):

a) Please explain why the project remains at a Class 3 cost estimate, given the scale and estimated cost of the redevelopment project.
b) Please explain whether Indigenous and stakeholder engagement has been initiated for this project. If not, please explain why engagement is planned for later stages of the project.
c) Please confirm whether a formal condition assessment of the penstock and associated hydraulic infrastructure has been conducted. If yes, please provide a summary of the findings.
d) Please describe any mitigation or contingency measures in place should deterioration of these structures occur prior to completion of the redevelopment project, in terms of public safety and environmental risk.

D1-01-Staff-319

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 27 / 86587
Ref 2: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 32 / 86937

Preamble:

The referenced filings indicate that refurbishment planning has progressed for R.H. Saunders Unit G16, but that priority later shifted to Unit G12 following a forced outage at G12.

Question(s):

a) Please explain whether the reprioritization from G16 to G12 resulted in any material change to cost, scope, schedule, outage planning or expected reliability risk for the referenced projects or for the broader R.H. Saunders refurbishment program.

D1-01-Staff-320

Ref 1: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 21 / 84907
Ref 2: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 20 / 84901
Ref 3: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 34 / 87197
Ref 4: Exhibit D1 / Tab 1 / Schedule 2 / Attachment 1 / Tab 36 / 87329

Preamble:

Projects 84907, 84901, 87197, and 87329 involve support infrastructure and facilities associated with hydroelectric operations.

Question(s):

a) For each of Projects 84907, 84901, 87197, and 87329 please describe the specific hydroelectric operational, maintenance, production, control-centre or refurbishment related functions expected to be supported by the proposed facility.
b) Please explain why each project is appropriately included within the hydroelectric capital program, rather than being treated as general facility or corporate support investments.
c) Please explain how OPG determined the proposed size, capacity or accommodation scope of each facility, relative to the anticipated hydroelectric operational need or expected refurbishment workload and how OPG assessed the risk of underutilization.

d) Please describe the expected utilization of each facility, including the number of staff, functions, activities, number and type of components or hydroelectric projects, as applicable, expected to rely on it.

EXHIBIT F – OPERATING COSTS

F1-01-Staff-321

Ref 1: Exhibit F1 / Tab 1 / Schedule 1 / pp. 21-27

Preamble:

Exhibit F1, Section 4.3 Reliability, presents the station-specific Availability / EFOR charts and supporting narrative for DeCew Falls 2 GS, Abitibi Canyon GS, Otter Rapids GS, Otto Holden GS, R.H. Saunders GS, Sir Adam Beck 1 GS, Sir Adam Beck 2 GS, and the historical Western Region forced-outage discussion for Manitou Falls GS.

Question(s):

a) For the referenced major hydro projects at charted or otherwise reliability-significant facilities, please provide a consolidated facility-by-facility explanation of how OPG determined each project's expected contribution to forecast Availability, reliability, and EFOR under Exhibit F1, Section 4.3. In particular:
   i. For each project, identify whether the principal expected benefit is Availability-side, EFOR-side, or primarily enabling/supporting in nature.
   ii. Identify whether each project's benefit is already embedded in the pre-2025 baseline or is assumed to contribute planned outage burden and/or post-project benefit during the 2025–2031 forecast period.
   iii. Identify the specific failure modes, operating restrictions, hydraulic/control limitations, electrical limitations, or structural/civil conditions being addressed.
   iv. For each charted facility, explain how the project sequencing and expected in-service timing were reflected in the station's forecast Availability and EFOR targets.
   v. Identify what residual reliability risk remains at each facility if the project is delayed, re-scoped, or not completed as planned.

vi. Explain how OPG distinguished between direct unit-refurbishment projects and indirect enabling/support projects, and how OPG avoided double counting reliability benefits where multiple projects support the same facility.

F2-01-Staff-322

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 2 / pp. 37-44

Preamble:

At Reference 1, OPG states:

> The refurbishment normalization methodology allows OPG to adjust the distribution of actual operating and capital costs to reflect Darlington's number of operating units rather than a four-unit site. OPG is performing a mid-life refurbishment at Darlington, which involves bringing units offline for the replacement of certain life-limiting components. It is necessary to normalize these metrics during refurbishment to allow for comparisons to prior site performance and industry peers, given reduced generation and no corresponding decline in fixed costs.

Question(s):

a) For each year from 2021-2023, please provide a table showing the adjustment made to each affected cost category.
b) Aside from the Darlington site, please provide a list of all plant refurbishments affecting the 57 nuclear sites studied by ScottMadden from 2006 to 2023.
c) Aside from the Darlington site, please confirm that no refurbishment normalizations have been applied to the costs of any other site.

F2-01-Staff-323

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / p. 9
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 4 / p. 7

Preamble:

At Reference 1, OPG states that ScottMadden analyzed eighteen years of Electric Utility Cost Group (EUCG) data (from 2006-2023) for OPG and it indicated that Canada Deuterium Uranium (CANDU) technology increases predicted Total Generating Cost (TGC) by over $539 million per year relative to non-CANDU plants and each month of average unit age increases predicted TGC by $77,000 per year. ScottMadden then adjusted the EUCG data to normalize for these factors.

At Reference 2, it illustrates the calculation of Darlington TGC adjustments based on econometric analysis and refurbishment costs.

Question(s):

a) Please clarify if the above updated study and normalization methodology applies to both Darlington's and Pickering's normalized TGC calculation in 2023 and their annual target calculation in 2026-2031.
b) Given the differences between the reactor design of the units at Pickering and Darlington, please clarify if there is any difference to account for the CANDU technology costs impact in the TGC normalization calculations between the two stations.
c) Given that Pickering will start refurbishment in late 2026, please clarify if any normalization is developed and applicable to Pickering's refurbishment project and its annual normalized TGC calculation in 2027-2031. If so, please provide calculation details similar to the calculation of Darlington TGC adjustments based on econometric analysis and refurbishment costs.

F2-01-Staff-324

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / pp. 8-9
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 4 / pp. 6-7

Preamble:

In Reference 1, OPG explains that ScottMadden conducted econometric analyses of Electric Utility Cost Group (EUCG) data for OPG and its industry peers to assess whether and to what extent site characteristics influence total generating cost (TGC) over time, and to normalize observed costs for those characteristics. In an earlier analysis using nine years of EUCG data (2009–2017), ScottMadden found that "CANDU technology increases predicted TGC by over $250M per year relative to non-CANDU plants, and each month of average unit age increases predicted TGC by $346,000 per year". In the current study, an expanded eighteen-year dataset (2006–2023) is used. ScottMadden reported "CANDU technology increases predicted TGC by over $539M per year relative to non-CANDU plants and each month of average unit age increases predicted TGC by $77,000 per year." In both cases, ScottMadden then adjusted the EUCG data to normalize these factors.

At Reference 2, ScottMadden notes in footnote 3 that the prior study's Canada Deuterium Uranium (CANDU) adjustment was $283.9 million in 2017 dollars, which inflation-adjusted to 2023 dollars would be ~$343.3 million — still substantially below the current $539 million figure. The document does not explain the factors driving this ~57% real increase in the CANDU technology cost penalty. Reference 2 also notes that there are only three CANDU plants in the 57-site EUCG dataset.

Question(s):

a) Please explain why a different data period is used in the current study.
b) Please confirm if the same set of "industry peers" is used in both analyses.
c) Regarding Reference 3, please explain step by step how ScottMadden arrived at the Plant Weighted Age variable found in the Weighted Performance Calcs tab.
d) Please explain the driving factors of the differences in the effect of average unit age on predicted TGC in the 2018 study and the 2025 study.
e) Please identify and quantify the factors that account for the increase in the CANDU technology adjustment from ~$343 million (2018 study, inflation-adjusted to 2023 dollars) to ~$539 million (2025 study, 2023 dollars), distinguishing between the effect of: (a) the expanded dataset period (9 years vs. 18 years), (b) changes in the composition of the EUCG peer panel, (c) actual cost increases at CANDU plants relative to Pressurized Water Reactor/Boiling Water Reactor peers, and (d) any other contributing factors.
f) Given that there are only three CANDU generating stations in the 57-site EUCG dataset, please discuss how ScottMadden assessed the statistical reliability of a coefficient derived from three generating stations within a dataset of 57 sites.

F2-01-Staff-325

Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 4 / p. 6 / footnote 2

Preamble:

At Reference 1, ScottMadden states "[w]e do not adjust costs for differences in site capacity, despite this being a significant driver of cost, since this would also have required a complex adjustment to generation."

Question(s):

a) Please explain why MW capacity was included in the econometric model if no adjustment to total generating cost (TGC) was made.

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Ref 1: Cost Model - With Formulas - BWR Base v4 (For OEB).xlsx
Ref 2: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 4

Preamble:

Reference 1 forms part of the confidential working papers that support ScottMadden's Nuclear Cost Performance Benchmarking study, Reference 2.

Question(s):

a) In the calculation of TGCperMWhOutageAdjusted within the "Cost per MWh Calcs" tab, please confirm whether or not Total_Generating_Costs is adjusted for inflation.

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Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 4 / p. 11
Ref 2: Master Data Adjusted For 0 Generation - ORIGINAL.xlsx
Ref 3: OPG Regression Analysis v0.07 (For OEB).R

Preamble:

At Reference 1, ScottMadden states:

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

Question(s):

a) Please explain why OPG Regression Analysis v0.07 (For OEB).R defines Planned_Outage_PCT using Outage_Hours rather than Planned_Outage_Hrs.
b) Please explain the difference between Outage Hours and Total Outage Hrs in Master Data Adjusted For 0 Generation - ORIGINAL.xlsx, tab “Master Compilation.” Please confirm that ScottMadden is using Outage Hours in its Nuclear Outages Analysis.
c) Using the sourcedataoutage data frame in OPG Regression Analysis v0.07 (For OEB).R, CAEC calculated the average share from 2006 to 2023 of planned outage hours (Planned_Outage_PCT) and the average age (Plant_Weighted_Age) for the three CANDU sites. To the extent that planned maintenance outages for CANDU reactors occur on a fixed schedule as described above, please explain the variation in average Planned_Outage_PCT across these three sites. In particular, despite having similar plant ages, explain why plant 967 and the Pickering plant have significantly different planned plant outage percentages.
d) Regarding Reference 3 and the Darlington plant capacity and planned outage percent from 2006 to 2023.
   i. Please explain how Planned_Outage_PCT is related to the mid-life refurbishment projects at the Darlington plant.
   ii. Please confirm that such projects affect reported capacity and MWh.

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Ref 1: Exhibit F2 / Tab 1 / Schedule 1 / Attachment 4 / p. 12

Preamble:

At Reference 1, ScottMadden states:

> ScottMadden adjusted the MWh values for all 57 sites from 2006-2023, as described above, to account for the impact of differences in planned outage durations across technology types and outage frequencies. In addition, the Darlington Refurbishment accounted for significant time in planned outage, but this outage time was captured in the reported unit capacity each year, so no further capacity adjustments were needed.

Question(s):

a) Please explain what is meant by "the Darlington Refurbishment accounted for significant time in planned outage, but this outage time was captured in the reported unit capacity each year, so no further capacity adjustments were needed."
b) Did ScottMadden consider whether or not such capacity adjustments were needed for other sites in the sample in addition to the Darlington site? If not, please explain.