VIA RESS and EMAIL

March 25, 2026

Ritchie Murray
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, Ontario M4P 1E4

Dear Ritchie Murray:

Re: Ontario Power Generation Inc. (OPG) and DNNP LP
2027-2031 Payment Amounts
Consumers Council of Canada (CCC) Interrogatories
OEB File No. EB-2025-0297

In accordance with Procedural Order No. 2, dated March 4, 2026, please find attached CCC's interrogatories with respect to Ontario Power Generation Inc.'s (OPG) 2027-2031 Payment Amounts application.

Yours truly,

Lawrie Gluck

Lawrie Gluck
Consultant for the Consumers Council of Canada

cc: All parties in EB-2025-0297

Ontario Power Generation Inc. and DNNP LP

2027-2031 Payment Amounts

Consumers Council of Canada

Interrogatories

March 25, 2026

General

1-CCC-1

Question(s):

Please update, as applicable, all Working Excel Tables to reflect 2025 actuals and any coincident impacts on the 2026-2031 period. Please also include as part of these updated tables any corrections or updates that were made as a result of the interrogatory process. Please include the revised tables in updated versions of the "Working Excel Tables". As part of the response, please also explain any material changes between the updates and the pre-filed evidence.

Exhibit A1 – Administration and Overview

A1-CCC-2
Ref: Exhibit A1, Tab 3, Schedule 1, p. 4

Preamble:

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

Question(s):

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

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

Question(s):

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

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

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

A1-CCC-4
Ref: Exhibit A1, Tab 3, Schedule 2, pp. 22-24

Question(s):

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

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

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

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

A1-CCC-5
Ref: Exhibit A1, Tab 3, Schedule 2, pp. 32, 34-35

Question(s):

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

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

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

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

A1-CCC-6
Ref: Exhibit A1, Tab 3, Schedule 2, Attachment 1, p. 16

Question(s):

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

A1-CCC-7
Ref: Exhibit A1, Tab 3, Schedule 2, Attachment 2, p. 32

Question(s):

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

A1-CCC-8
Ref: Exhibit A1, Tab 3, Schedule 2, Attachment 3, pp. 5-7

Question(s):

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

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

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

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

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

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

A1-CCC-9
Ref: Exhibit A1, Tab 4, Schedule 1, Attachment 4, pp. 13, 22, 31-32, 49-50, 81

Question(s):

a) Please provide all of the internal audits with a yellow or red report rating as listed in Exhibit A1, Tab 4, Schedule 1, Attachment 4.

b) Please discuss the implications of certain fleet assets being acquired outside of the Fleet Management group. As part of the response, provide the total cost of the fleet assets procured outside of the Fleet Management group.

c) Please provide a brief summary and the costs of the following projects (broken out between capital and operations):

   i. Re-Imagine 1.0

ii. RG Turbine Generator Overhaul

d) Please file the 24-15 DNNP Business Case and Release Quality estimate audit.

A1-CCC-10
Ref: Exhibit A1, Tab 4, Schedule 4, pp. 2-3, 10

Question(s):

a) Please file the following agreements:

i. DNNP LP and OPG Lease Agreement
ii. DNNP LP and OPG Reimbursement Agreement
iii. DNNP LP and OPG PMA
iv. DNNP LP and OPG MOMA

b) Please further explain the conditions that must be satisfied in order for CGF and BOF to acquire minority interests in DNNP LP.

c) To the extent that it is available, please file the "audited schedule of costs that is approved by Ontario Power Generation Inc.'s board of directions as at the transfer date" regarding the assets to be transferred from OPG to DNNP LP (which will be considered the opening CIP balance for DNNP LP).

d) Please further explain the statement that "DNNP LP will reimburse OPG for all construction in progress costs through the issuance of ownership units."

A1-CCC-11
Ref: Exhibit A1, Tab 4, Schedule 4, Attachment 1, pp. 1-3

Question(s):

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

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

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

A1-CCC-12
Ref: Exhibit A1, Tab 4, Schedule 4, Attachment 1, pp. 1-3

Question(s):

a) In many places in the evidence, there are statements regarding OPG and DNNP LP delivering the first SMR in the G7.

  i. Please explain why constructing and operating the first SMR is a benefit to ratepayers.
  ii. Please discuss the risks of constructing and operating a FAOK generation station.
  iii. Please discuss whether, and to what extent, ratepayers are the beneficiaries of any special (i.e., discounted) pricing mechanisms from the technology provider (GE-Hitatchi)
  iv. Please discuss whether, and to what extent, OPG or DNNP LP have ownership of intellectual property or other agreements that may result in new revenue streams. If yes, please advise whether these new revenue streams will operate to offset revenue requirement for the benefit of ratepayers.
  v. Please discuss whether, and to what extent, OPG's unregulated affiliates have ownership of intellectual property or other agreements that may result in new revenue streams. If yes, please advise whether these new revenue streams will operate to offset revenue requirement for the benefit of ratepayers.

b) Please file any agreements as between DNNP LP, OPG, CGF and BOF regarding the new nuclear facilities (including the Equity Commitment Agreements).

A1-CCC-13
Ref: Exhibit A2, Tab 3, Schedule 1

Question(s):

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

Exhibit A2 - Business Planning and Budgeting

A2-CCC-14
Ref: Exhibit A2, Tab 2, Schedule 1, p. 5

Preamble:

Without any form of payment amount shaping, the 2027 total bill increase would be approximately 7.3%. This one-year increase is primarily due to a temporary decrease in Darlington generation as a result of a unique combination of planned outages in that year, including the four-unit vacuum building outage that is a regulatory requirement of the CNSC.

Question(s):

a) Please confirm that the Darlington vacuum building outage in 2027 was not included in the production forecast that underpinned rates in any year prior to 2027. If not confirmed, please provide details as to when the outage was originally scheduled.

b) Please confirm that the vacuum building outage can only be deferred with the permission of the CNSC.

c) Please comment on the possibility that OPG may apply to the CNSC to have the vacuum building outage related work deferred, including the maximum number of years of any such deferral.

A2-CCC-15
Ref: Exhibit A2, Tab 2, Schedule 1, p. 11

Preamble:

To address these risks, OPG conducted a comprehensive review supported by independent analysis, confirming sustained escalation pressures through 2031 for construction material.

Question(s):

Please provide the comprehensive review and the supporting independent analysis referred to by OPG in this passage. If already included in the application, please provide the cite for the material.

A2-CCC-16
Ref: Exhibit A2, Tab 2, Schedule 1, Attachment 2, p. 9

Preamble:

OPG also begins support of new nuclear in Saskatchewan and Alberta, and other international jurisdictions including Poland, UK, and beyond through Laurentis Energy Partners.

Question(s):

Please explain whether, and if so how, OPG accounts for the costs and revenues that are associated with projects outside of Ontario in its revenue requirement. Please comment on the materiality of any such work outside of Ontario.

A2-CCC-17
Ref: Exhibit A2, Tab 2, Schedule 1

Preamble:

There does not appear to be any mention of rate impacts or affordability concerns as drivers within the business planning process.

Question(s):

Please confirm that OPG does not provide instructions as part of the planning process relating to the consideration of rate impacts or affordability of the proposed plans, either overall or at the business unit level. If confirmed, please explain why OPG does not consider rate impact or affordability for its customers in its planning process. If not confirmed, please provide cites to the evidence where rate impact and affordability were explicitly considered by OPG in its planning process.

Exhibit B1 - Rate Base

B1-CCC-18
Ref: Exhibit B1, Tab 1, Schedule 1, pp. 6, 8-9

Question(s):

a) With respect to the D2O Storage Project, please further explain the statement that "the rate base values in the Application reflect the results of [OEB] review." As part of the response, please provide the rate base value that has been removed for each year of the historical and forecast period.

b) Please provide a list of all permanent rate base disallowances (both hydroelectric and nuclear) ordered by the OEB and show how those disallowances are reflected in the regulated PP&E continuity schedules.

c) Please confirm, or correct, CCC's understanding regarding the conversion of in-service additions (for both hydroelectric and nuclear assets) to rate base for forecasting purposes as follows:

    i. For in-service additions with a value below $50M, the half-year rule is applied.
    ii. For in-service additions with a value above $50M, a forecast of the day/month that the asset will enter service is applied (i.e., the ISA is weighted to the day/month that it is expected to enter service).

d) With respect to in-service additions with a value below $50M, please explain whether OPG has the ability to forecast the month that the asset is expected to enter service.

e) With respect to the determination of depreciation expense associated with in-service additions for forecasting purposes, please confirm, or correct CCC's understanding as follows:

    i. For in-service additions with a value below $50M, depreciation is calculated based on the assumption that the asset enters service mid-year (i.e., half-year rule).
    ii. For in-service additions with a value above $50M, depreciation expense reflects the forecast month that the asset enters service (i.e., if an asset enters service on November 1, two months of depreciation expense are reflected in the revenue requirement).

B1-CCC-19

Ref: Exhibit B1, Tab 1, Schedule 1, p. 14
Exhibit A1, Tab 4, Schedule 1, Attachment 4, p. 49

Question(s):

a) Please further discuss the statement that the market value of materials and supplies takes into account technological obsolescence and remaining useful life. To the extent that certain materials that were purchased and not used, please explain how those costs are treated from a ratemaking perspective.

b) Please explain whether the MRNI reduction initiative (discussed as part of the 23-08 Nuclear Work Orders Materials Management audit) is related to minimizing unutilized materials and supplies. If not, please explain the noted MRNI initiative.

c) For the historical period, please provide the dollar value of materials/supplies that were purchased and evaluated as not consumed by year.

<u>Exhibit C1 – Capital Structure and Cost of Capital</u>

C1-CCC-20
Ref: Exhibit C1, Tab 1, Schedule 1

Question(s):

a) Please advise whether the Government of Ontario is explicitly aware of OPG's proposal to increase the equity thickness from 45% to 52% for the test period. If so, please explain how the government was informed of this proposal. As part of the response, please also discuss whether the Government of Ontario is aware of the bill impacts resulting directly from this change.

b) Please provide the impact on total 2027-2031 revenue requirement of a 1% change to equity thickness based on the proposals in the application.

c) Please file on the record of the current proceeding all of the cost of capital-related studies that were filed in the EB-2016-0152 and EB-2020-0290 proceedings.

C1-CCC-21
Ref: Exhibit C1, Tab 1, Schedule 1, p. 3

Question(s):

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

C1-CCC-22
Ref: Exhibit C1, Tab 1, Schedule 1, Attachment 1, p. 19

Preamble:

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

Question(s):

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

C1-CCC-23

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

Question(s):

a) Please provide Figure 3 in tabular format.

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

C1-CCC-24

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

Question(s):

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

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

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

C1-CCC-25

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

Preamble:

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

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

Question(s):

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

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

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

C1-CCC-26
Ref: Exhibit C1, Tab 1, Schedule 1, Attachment 1, pp. 49, 101-102

Question(s):

a) Please provide the credit metrics analysis shown in Exhibit 1 to the Report in excel format.

b) Please confirm that the only change made between the two analyses (Exhibit 1 to the Report) is to the equity portion of the capital structure (and all other non-calculated costs in the table remain unchanged).

c) Please provide the same information as is provided in Exhibit 1 for the period 2017-2026 using the OEB-approved equity ratio over that period in excel format.

C1-CCC-27
Ref: Exhibit C1, Tab 1, Schedule 1, Attachment 1, p. 51

Question(s):

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

C1-CCC-28
Ref: Exhibit C1, Tab 1, Schedule 1, Attachment 1, p. 52

Question(s):

a) Please further explain the statement that "OPG is at risk for variability in the output at its nuclear plants, a factor that distinguishes OPG from other North American regulated generators." As part of the response, please explain how other North American generators recover their costs and describe any mechanisms that are applied to those generators with respect to truing-up production forecasts.

b) In terms of Concentric's proxy group, please list all of the peer companies that have no, or less, risk related to the variability of generation output due to rate design or regulatory treatment. As part of the response, please provide a detailed description of the rate design approach or other regulatory treatment that reduces production forecast risk

c) With respect to the nuclear business, please further explain the change in OPG's risk related to weather events.

d) Please provide Concetric's views on the impact to OPG's risk of the planned purchase of nuclear business interruption insurance for Darlington beginning in 2027, which the Company has not purchased coverage for in the past.

C1-CCC-29
Ref: Exhibit C1, Tab 1, Schedule 1, Attachment 1, pp. 55-59

Question(s):

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

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

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

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

C1-CCC-30
Ref: Exhibit C1, Tab 1, Schedule 1, Attachment 1, pp. 63-64, 103-106

Question(s):

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

b) Please provide Exhibit 2 in excel format.

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

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

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

C1-CCC-31

Ref: Exhibit C1, Tab 1, Schedule 1, Attachment 1, pp. 67, 107-109

Question(s):

a) Please confirm that the following table is correct (with the addition of the most credit supportive peer group) or otherwise correct the table. If available, please also add the actual equity ratio (5-year average) for the most credit supportive peer group.

	Concentric Proxy Group		*Nuclear Group*		*Hydro Group*		*Most Credit Supportive Group*	
Peer Group Equity Ratios	Actual	Authorized	Actual	Authorized	Actual	Authorized	Actual	Authorized
Mean	52.97%	50.13%	52.89%	52.92%	51.75%	50.49%		49.30%
Median	52.80%	51.21%	53.23%	52.50%	52.54%	50.00%		52.15%

b) In the scenario that the OEB is interested in considering two separate capital structures for nuclear and hydroelectric, please provide Concentric's recommended capital structure for each of the two generation types.

c) Please provide Exhibit 4 in excel format.

d) Please further explain the note at page 2 of Exhibit 4 as follows, “U.S. states that account for zero-cost of capital items in utilities' regulated capital structure (Florida, Arkansas, Indiana, and Michigan) were excluded from this analysis.”

e) Please further explain the note at page 2 of Exhibit 4 as follows, “Florida Power & Light's authorized equity ratio was included based on an analysis of the capital structure excluding zero cost of capital effects.” Please provide a detailed explanation of any adjustments made to determine the current equity ratio for Florida Power and Light.

f) Please explain the “n/a” designations shown in Exhibit 4. If the current equity ratio for the operating subsidiaries where this ratio has been designated as “n/a” are available, please provide an alternative version of Exhibit 4 that includes these ratios in excel format.

g) As an example, in EB-2024-0063 at Exhibit CEA-10.3, the Indiana Michigan Power Company (operating in Indiana) (a subsidiary of American Electric Power Company) is shown to have an authorized equity ratio of 40.7% and in the current proceeding the equity ratio is listed as “n/a.” Please explain why this subsidiary was included in the EB-2024-0063 equity thickness analysis and is excluded in the current proceeding.

h) Please provide an alternative Exhibit 4 authorized equity ratio analysis using a 5-year average of the authorized ratios (instead of only the current authorized ratio) in the circumstance that the authorized ratio has changed over the most recent 5-year period.

i) Please confirm that the average authorized equity ratio for the operating subsidiaries of Canadian companies is 46.35%.

j) Please confirm that the average authorized equity ratio for the operating subsidiaries that operate within Canada is 40.60%.

k) Please confirm that the holding company averages (Exhibit 4, p. 3 of the report) includes only the electric subsidiaries of the holding companies (i.e., page 3 is simply an average of the equity ratios for the electric subsidiaries of each holding company as shown on pages 1-2 of Exhibit 4).

C1-CCC-32
Ref: Exhibit C1, Tab 1, Schedule 1, Attachment 1, p. 69

Question(s):

a) Please provide a definition for each regulatory mechanism listed in Figure 18.

b) Please provide a table that lists each of peers in the Concentric proxy group and highlights whether each specific peer is applied each of the regulatory mechanisms listed in Figure 18. Please also include OPG (and Concentric's view on the application of these regulatory mechanisms to OPG) in this table.

C1-CCC-33
Ref: Exhibit C1, Tab 1, Schedule 1, Attachment 1, p. 71

Question(s):

a) Please provide an alternative version of Figure 20 that shows the full breakdown of the generation capacity by type. For example, Duke Energy has 9,200 MW of nuclear generation capacity and 1,300 MW of hydroelectric generation capacity. Please provide a breakdown of the other types of generation capacity that bring the total regulated generation capacity to 54,000 MW. Please also provide the data underlying this alternative version of Figure 20 in excel format.

C1-CCC-34
Ref: Exhibit C1, Tab 1, Schedule 1, Attachment 1, pp. 84-86

Question(s):

Please file all the credit agency reports referenced in Appendix B (pp. 84-86 of the report).

C1-CCC-35
Ref: Exhibit C1, Tab 1, Schedule 2, pp. 2, 5-7

Question(s):

a) Please discuss the likelihood that OPG will access the U.S. bond market during the 2027-2031 period.

b) Please provide the underlying calculations for Charts 1 & 2 showing the application of the equally weighted blend of the two Bloomberg forecasts (and the adjustment for the years where the Bloomberg Bond Yield Median forecast was not available).

c) Please provide the credit spreads for each year of the three-year average that supports the 135-basis points credit spread for 10-year bonds and the 160-basis point credit spread for 30-year bonds.

d) Please provide the historical data supporting the issuance costs included in forecast long-term debt rates.

e) Please provide the current 30-year GoC bond rate at the time of filing the IR responses.

f) Please provide the 10-year bond forecast for 2027-2031 based on the previous approach used by OPG (i.e., Global Insight bond rate forecast).

g) Please advise whether OPG has a recent credit spread quote from the major banks (i.e., a point in time estimate received at the time it was preparing the current application). If so, please provide the credit spread(s).

C1-CCC-36

Ref: Exhibit C1, Tab 1, Schedule 3, pp. 1-3
Exhibit C1, Tab 1, Schedule 3, Table 2

Question(s):

a) Please provide the calculations underpinning the interest rates shown in Line 2 of Table 2.

b) Please provide the historical information supporting the 17-basis point corporate spread over the OIS rate.

c) Please provide the short-term debt rate for the 2027-2031 period based on the previous approach applied by OPG (i.e., Global Insight forecast).

d) Please advise whether the 10-basis point dealer fee is still applied in OPG's updated approach to establishing the short-term debt rate.

e) Please provide the calculation supporting the bank credit facility fees for each year of the 2027-2031 period.

Exhibit C2 - Nuclear Waste Management and Decommissioning

C2-CCC-37
Ref: Exhibit C2, Tab 1, Schedule 1, Table 1
EB-2020-0290, Exhibit C2, Tab 1, Schedule 1, Table 1

Preamble:

The 2022 to 2024 actual total nuclear liabilities are materially different then the forecast 2022 to 2024 nuclear liabilities that were included in OPG's 2022 to 2024 rates.

Question(s):

a) Using the categories of cost in Table 1, please explain which elements of the nuclear liabilities revenue requirement are ultimately a pass through as a result of the operation of deferral/variance accounts, the ONFA, or other reasons, and which elements of the nuclear liabilities revenue requirement, if any, OPG bears the risk for in the event the actual amount varies from the amount embedded in rates. Please explain which categories are subject to adjustment each time the ONFA is updated.

b) Please confirm that for elements that are subject to deferral/variance accounts, both positive and negative variances are tracked. If not confirmed, please explain how and why the accounts operate asymmetrically.

Exhibit D1 / Tab 1 – Regulated Hydroelectric Capital

D1-CCC-38
Ref: Exhibit D1, Tab 1, Schedule 1

Preamble:

The evidence discloses a $1.8B increase in hydroelectric related capital spending in the 2027 to 2031 period relative to the 2022 to 2026 period.

Question(s):

a) OPG's capital forecast for 2027-2031 includes several large one-time rehabilitation projects. Has OPG analyzed what the long-run steady-state capital requirement of the hydroelectric fleet is once these projects are completed? If so, please provide that analysis.

b) Does OPG expect the trend in hydroelectric capital spending to be sustained at the proposed level, increase materially, or decrease materially, beyond the 2027 to 2031 period? Please explain.

D1-CCC-39
Ref: Exhibit D1, Tab 1, Schedule 1

Preamble:

At various places, the evidence notes incremental capacity created by some of the capital projects.

Question(s):

What is the total incremental generating capacity, by year realized, expected to result from the hydroelectric capital investments during the 2027–2031 period?

D1-CCC-40

Ref: Exhibit D1, Tab 1, Schedule 1, p. 1

Preamble:

OPG is planning increased capital investment during the forecast period to address the conditions of aging assets within its regulated hydroelectric fleet. The average age of OPG's regulated hydroelectric stations is approximately 90 years (ranging from 2-127 years).

Question(s):

a) What is the average expected useful operating lifespan for OPG's hydroelectric assets before OPG would expect to have to address "aging asset" related problems?

b) How much of the 2027 to 2031 hydroelectric capital spending is related to regulated hydroelectric stations that are 90 years or older?

c) Please provide a table that shows:

   i) the age of assets in years from 1-127, and
   ii) the amount of capital spending in the 2027 to 2031 period related to assets of each age.

<u>Exhibit D2 / Tab 1 – Nuclear Capital</u>

D2-CCC-41
Ref: Exhibit D2, Tab 1, Schedule 2, p. 3
Exhibit D2, Tab 1, Schedule 3, Table 4b

Question(s):

a) Please further explain how OPG determined whether a project should be defined as a Pickering Refurbishment-related project or a Pickering portfolio project.

b) Please advise whether Pickering portfolio projects are trued-up through the CRVA.

c) Please confirm that all of the Pickering sustaining projects planned for the CIR term (2027-2031) are being completed while the Pickering station is offline for refurbishment. If this is not correct, please list the projects (and related project costs) that are being completed outside the period where the station is offline.

d) There are capital in-service additions in each year of the 2027-2031 period related to Pickering sustaining projects (Table 4b). Please explain why any of these assets would be placed in-service in advance of the completion of the first unit's refurbishment.

D2-CCC-42
Ref: Exhibit D2, Tab 1, Schedule 2, pp. 12-19

Question(s):

a) For each of the Darlington-related new non-portfolio projects that were not considered part of the DRP scope (Projects 83664, 86693, 87151, 89281, 87807, 87811, 84764, 89462), please provide evidence supporting that these project costs have not already been captured in the $12.8B DRP forecast cost.

b) Please provide the total cost of the DRP inclusive of the cost of the projects listed in part (a) to this question.

c) With respect to the Darlington Water Treatment Plant:

   i. Please advise whether any capital in-service additions were reflected in the EB-2020-0290 proceeding for the CIR term. If so, please provide the quantum and timing of those proposed in-service additions that were reflected in rate base for ratemaking purposes.

   ii. Please advise provide detailed evidence supporting the $68.1M 2025 opening rate base value.

   iii. Please explain the statement that the capital asset value "excludes yet to be incurred scheduled rehabilitation payments." As part of the response, please discuss whether these payments will be treated as operational costs when they are made.

d) With respect to the Pickering Water Treatment Plant Lease, please advise whether OPG expects that any of the capital costs will be placed in-service during the 2027-2031 period. Please also advise whether this project is considered part of the scope of the PRP.

D2-CCC-43
Ref: Exhibit D2, Tab 1, Schedule 3, Table 4a

Question(s):

Please confirm that the reductions to nuclear operations capital ISAs resulting from the EB-2020-0290 Decision were applied only at the aggregate level. As part of the response, please advise whether there is any reasonable manner to disaggregate the reduction across the various categories.

D2-CCC-44
Ref: Exhibit D2, Tab 1, Schedule 3, Table 4b
Exhibit D2, Tab 1, Schedule 3, Tables 5a-5d

Question(s):

a) If available, please provide the expected in-service date(s), cost estimates, and capital in-service additions by year for the unallocated projects listed in Tables 5a-5d.

b) Please advise whether the total estimated in-service amount for the 2027-2031 period related to the unallocated projects listed in Tables 5a-5d is equivalent to the unallocated project in-service amount totals listed in Column "j" of Table 4b. If not, please explain the difference between those total values.

<u>Exhibit D2 / Tab 2 – Darlington Refurbishment Program</u>

D2-CCC-45

Ref: Exhibit D2, Tab 2, Schedule 1, p. 1
Exhibit D2, Tab 1, Schedule 3, pp. 16-17

Question(s):

a) Please file the Levelized Cost of Electricity (LCOE) for the DRP. Please provide the detailed calculation and all underlying assumptions as part of the response.

b) Please file the LCOE for the DRP inclusive of the $2.6 billion cost of the Darlington Turbine Rotors Replacement Project (Project # 87807 & 87811). Please provide the detailed calculation and all underlying assumptions as part of the response.

D2-CCC-46
Ref: Exhibit D2, Tab 2, Schedule 3, p. 3

Question(s):

a) Please provide a more detailed breakdown of the Unit 4 cost variance between approved and actual.

b) Please provide additional details with respect to the CanAtom Execution Phase incentive.

c) Please explain why the CanAtom incentive and demobilization costs were not assigned to Unit 4 in EB-2020-0290.

<u>Exhibit D2 / Tab 3 – Pickering Refurbishment Program</u>

D2-CCC-47
Ref: Exhibit D2, Tab 3, Schedule 1, p. 5

Preamble:

This Application seeks approval for the following in respect of the PRP:

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

- OM&A expenditures of $100.3M in 2027, $94.1M in 2028, $84.9M in 2029, $52.7M in 2030, and $46.5M in 2031 (see Ex. F2-8-1).

- PRP CCR interest amounts on a forecast basis totaling $2,923.3M over the 2027-2031 period as described in Ex. I1-1-3 and calculated in Ex. I1-1-1, Table 7. If actual CCR interest amounts are different from the forecast amounts, the difference will be recorded in the Pickering B Refurbishment Project Variance Account for future disposition.

Question(s):

Is OPG seeking approval of the overall PRP budget of $26.84B, despite the fact that only $9.868B is forecast to go into service between 2026 and 2031? CCC asks, because it appears the request for approval of CCR interest amounts is based on approved capital spending from 2026 to 2031 of at least $18.2466B per Exhibit I, Tab 1, Schedule 1, Table 7.

D2-CCC-48
Ref: Exhibit D2, Tab 3, Schedule 3, p. 3

Preamble:

CONTRACTS FOR MAJOR WORK BUNDLES

This section describes the contracts used for the major work bundles, as well as the Extended Services Master Services Agreement ("ESMSA"), which is the contract being used for the majority of the Balance of Plant work bundle.

Section 3.1 provides an overview of the different forms of contracting and some of the common terms across the contracts. Sections 3.2-3.8 consider the contracts for each of the major work bundles.

Question(s):

Please provide the contracts underpinning the PRP major work bundles.

D2-CCC-49
Ref: Exhibit D2, Tab 3, Schedule 3, p. 6

Preamble:

OPG's major contracts for the PRP include the following pricing models:

- Target Price – Under target pricing, the contractor is paid its <u>actual (allowed) costs</u> (other than overhead costs) incurred in performing the work and is entitled to a fixed fee as compensation for all of its overhead costs and profit. The target price incentive and disincentive mechanism, which includes a neutral band, is structured to achieve alignment of all parties' interests in the completion of the work. Outside the neutral band, the parties share savings below targets and overruns above targets.

- Fixed Price/Firm Price – Contractors complete their work within a set budget and time period. Price only varies in specified circumstances or where OPG changes scope. The price of fixed price contracts is a defined value whereas firm price contracts allow an escalation for inflation.

- Reimbursable Costs or Cost-Plus Mark-up – Contractors are paid <u>actual labour</u> and materials with mark-ups for overhead and profit (as a percentage of costs).

- Time and Materials – Contractors are paid in accordance with predetermined hourly rates for work performed for OPG. The rates are inclusive of profit and overhead. (emphasis added)

Question(s):

Please provides details with respect to the referenced "allowed costs" under target pricing, the "actual labour costs" under Reimbursable Costs or Cost-Plus Mark-up pricing, and the "predetermined hourly rates" under Times and Material pricing.

D2-CCC-50

Ref: Exhibit D2, Tab 3, Schedule 3, p. 3
Exhibit D2, Tab 3, Schedule 7, p. 7
Exhibit D2, Tab 3, Schedule 9, Attachment 1, p. 17

Preamble:

Reimbursable costs are the Contractor's actual costs incurred in the performance of its work and calculated in accordance with the cost allocation table.

Authorization of the use of contingency funds is strictly controlled through the Change Control Board, which requires an explanation of the risk or uncertainty element that has been realized and requires escalation for use of any contingency funds. Additional information regarding the Change Control Board is found under Ex. D2-3-9.

The Refurbishment Project Controls organization has resources dedicated to the Refurbishment program. Staffing will follow the matrix model by assigning Project Controls staff to specific bundles in addition to centralized Program support. Labour charges will be assigned to cost accounts per the OPG Cost Model.

Question(s):

a) Please provide a copy of the referenced cost allocation table.

b) Please confirm that through the use of the Change Control Board, OPG will, at the completion of the PRP, be able to explain in detail the cause of each use of the Contingency Amount, forecast to be $3.764B.

c) Please explain the nature and use of the OPG Cost Model in the context of the PRP. Please provide a copy of the OPG Cost Model (live, if applicable) and any written instructions with respect to its use.

D2-CCC-51
Ref: Exhibit D2, Tab 3, Schedule 8, p. 11-16, Charts 6, 7, 8, 9, 10 and 11

Preamble:

The cited charts break down the costs associated with each project bundle between the categories of “Project Management”, “Functional Labour”, “Inspections”, “Engineering”, “Procurement”, “Construction”, and “Commissioning and Close-out” costs.

Throughout the evidence, OPG notes its bottom-up approach to estimating the cost of the PRP.

Question(s):

a) For each category of cost within each chart (excluding escalation), please split the category between labour costs and material costs. Please maintain separation between charts.

b) For each subcategory created in part (a), please further split each subcategory between OPG internal costs (i.e. OPG internal staff related labour and materials procured directly by OPG) and 3rd party costs (i.e. 3rd party labour costs and materials procured by 3rd parties).

c) For each of the labour subcategories created in part (b), please provide a schedule of the trades and non-trades positions that underpin the estimated costs, the number of hours (or, if applicable, other unitized measure of effort) forecast for each position used to underpin the estimated costs, the hourly (or other) rates used to underpin the estimated costs, the methodology used by OPG to benchmark the reasonableness of the hourly (or other) rates, and any written material underpinning the use of those benchmarking methodologies by OPG.

d) For the OPG internal labour costs, please confirm that those costs are included in OPG's overall compensation evidence, i.e. to the extent that the PRP estimate relies on the use of internal OPG labour, the cost of that labour is included in OPG's compensation benchmarking analysis. If not confirmed, please explain what evidence OPG relies on to establish the reasonableness of the cost of OPG internal labour in the PRP estimate.

e) Please identify the 10 trade positions that account for the most estimated hours of work on the PRP, along with the number of hours included in the PRP estimate for each of those positions.

D2-CCC-52
Ref: Exhibit D2, Tab 3, Schedule 10, Attachment 1, p. 4

Preamble:

Based on Pegasus-Global Holdings, Inc.'s ("Pegasus-Global's") review of Ontario Power Generation Inc.'s ("OPG's") pre-execution planning of the PRP, I conclude that as OPG progresses through the Definition phase and prepares for the Execution phase, it has demonstrated an appropriate advancement towards readiness to execute the PRP through comprehensive pre-execution planning supported by a robust governance structure, extensive experience with megaproject execution, development of a Class 3 RQE, a mature governance framework, a contracting strategy that utilizes incentives and disincentives, implementation of a suite of project controls that align with recognized industry standards, and robust succession planning and knowledge management initiatives across the organization.

Question(s):

Please confirm that Pegasus-Global's report relates to OPG's execution readiness with respect to the PRP, and does not constitute an opinion as to the prudence or the reasonableness of the overall cost estimate. If not confirmed, please provide references in Pegasus-Global's report where Pegasus-Global purports to provide an opinion of the prudence or reasonableness of the estimated cost of the PRP beyond its assertion as to OPG's execution readiness, including any material provided by OPG to Pegasus-Global in support of the prudence or reasonableness of the cost estimate.

D2-CCC-53
Ref: Exhibit D2, Tab 3, Schedule 8, Attachment 2, pp. 1, 9.

Preamble:

KPMG LLP ("KPMG") was engaged by OPG to conduct an independent review of the governance, processes, and classification of the Release Quality Estimate ("RQE") for the Pickering Refurbishment Project ("PRP" or the "Program").

Escalation factors used to account for increases in market pricing between the time of the benchmark data and current day (where traceable) appear to have been based on the Consumer Price Index (CPI) rather than indices more reflective of the construction industry (e.g., StatCan's Building Construction Price Index). Construction costs have risen considerably in the past 6 years (i.e., ranging from 30% to 50%) which exceeds CPI increases (typically 2% to 3% annually). During the review and based on subsequent consultation with OPG, it was noted that escalation factors had been applied to approximately 6% of the Review Sample where benchmarking cost data was utilized.

Question(s):

Please confirm that KPMG LLP's report relates to the accuracy of the PRP estimate based on the inputs provided to KPMG LLP by OPG, and does not constitute an opinion as to the prudence or the reasonableness of the overall cost estimate. If not confirmed, please provide references in the KPMG LLP report where KPMG purports to provide an opinion of the prudence or reasonableness of the estimated cost of the PRP beyond its assertion as to the accuracy of the estimate based on inputs provided by OPG, including any material provided by OPG to KPMG in support of the prudence or reasonableness of the cost estimate.

Exhibit D2 / Tab 4 – Darlington New Nuclear Program

D2-CCC-54

Ref: Exhibit D2, Tab 4, Schedule 1, p. 3
EB-2023-0336, Exhibit H1, Tab 1, Schedule 1, p. 39

Preamble:

In EB-2023-0336, OPG stated that the majority of the costs incurred was related to selecting an appropriate technology for the Darlington SMR. OPG's key objectives for this process were:

- ensuring compatibility with the existing environmental parameters as outlined within the CNSC's Licence to Prepare Site for the Darlington new nuclear site,
- ensuring readiness for submission of the License to Construct application to the CNSC, and
- targeting an in-service date for the first unit by the end of 2028.

Question(s):

Please explain the implications of a later in-service date (i.e., expected end of 2030 in the current application and was expected at the end of 2028 in the previous proceeding) on the alternatives that OPG was considering as part of the technology selection process in 2021 (and prior to that). As part of the response, please advise whether assuming a longer timer to completion would have impacted the technology selection that was ultimately made.

D2-CCC-55
Ref: Exhibit D2, Tab 4, Schedule 2, Attachment 3, pp. 26-28

Question(s):

a) When did the in-service date for the first SMR at Darlington change from end of 2029 as shown in the Project Charter to October 2030. Please explain the reason for the change to the in-service date.

b) With respect to one of the success factors for the DNNP, the Project Charter states that the "total cost of generation [is] competitive in the Canadian energy market (carbon cost factored in)". Please provide the analysis that was originally completed, which compares the estimated cost of generation from the DNNP project to other nuclear and non-nuclear sources of electricity. If no such analysis was completed in advance of the Project Charter, please explain why. If OPG has received this type of analysis from the IESO, please provide the IESO's analysis on the record of the current proceeding.

c) Please provide a table that compares the estimated total cost per MW and MWh of output for the four unit DNNP once fully operational to the estimated total cost per MW and MWh for Darlington (once fully operational after refurbishment), Pickering (once fully operational after refurbishment), and for any potential new nuclear stations (e.g., Wesleyville, etc.) that OPG is currently evaluating. Please also provide the same comparison on a levelized cost of electricity (LCOE) basis. Please provide all calculations and assumptions that underpin the comparison. If this analysis is not available, please explain why not.

d) Please provide a table that compares the estimated total cost per MW and MWh of output of Unit 1 of the DNNP on a standalone basis to the estimated total cost per MW and MWh for Darlington (once fully operational after refurbishment), Pickering (once fully operational after refurbishment), and for any potential new nuclear stations (e.g., Wesleyville, etc.) that OPG is currently evaluating. Please also provide the same comparison on a levelized cost of electricity (LCOE) basis. Please provide all calculations and assumptions that underpin the comparison. If this analysis is not available, please explain why not.

e) Please explain how the discontinuance of the federal carbon charge impacts the economic feasibility of the DNNP.

f) Please further discuss how the DNNP supports the "establishment of a Canadian supply chain related to SMR build and maintenance..."

D2-CCC-56

Ref: Exhibit D2, Tab 4, Schedule 3, pp. 7-11
Exhibit D2, Tab 4, Schedule 7, p. 8

Question(s):

a) Please further explain why Kiewit Nuclear Canada Corp. was added as a Non-Owner Party (NOP) after the Validation Phase was completed. As part of the response, please advise whether Kiewit was part of the initial team that was recommended by the designer (and accepted by OPG).

b) Please provide a more detailed explanation regarding how the monthly overhead payment is calculated for each NOP. As part of the response, please further explain how OPG decided what percentage of overhead to hold back.

c) Using the terminology in Figure 1, please provide the total of each the target cost, the reward pool, and the risk pool. Please explain the difference between this cost and the total Unit 1 RQE of $7.7 billion.

d) Please confirm that Chart 1 is showing that OPG is funding $615M of the total cost of the reward framework.

e) Please provide a reconciliation of Chart 1 in Exhibit D2, Tab 4, Schedule 3 and Chart 1 in Exhibit D2, Tab 4, Schedule 7 showing which portions of the Unit 1 contingency by component are flowing into the various reward framework sub-pools.

f) Please advise whether, in the absence of the reward structure, the entirety of the OPG funded portion of the reward pool would flow back to ratepayers if contingency funding was, on an actual basis, not required.

g) Please provide the percentage of the execution reward pool that is eligible for payment to the NOPs if all of the critical milestones are completed.

h) Please advise whether all of the critical milestones could be met, and the associated milestone-related reward payments made during the construction period, but the fully completed project is at an actual cost that requires the entirety of the reward pool funding (i.e., IPA scope contingency funding). Please explain the implications of this scenario and whether OPG or the NOPs would be responsible for paying this incremental cost.

D2-CCC-57

Ref: Exhibit D2, Tab 4, Schedule 3, pp. 14-15

Question(s):

Please advise whether OPG has completed a subsequent financial audit under the IPA since Q3 2023. If so, please provide a summary of the outcome of that audit.

D2-CCC-58
Ref: Exhibit D2, Tab 4, Schedule 8, pp. 1, 3, 8, 16-17

Question(s):

a) Please provide a detailed breakdown of all costs incurred (broken down between capital and non-capital) related to the DNNP that are outside of the Unit 1 RQE of $7.7 billion. To the extent possible, please categorize these costs based on their relationship to each of the four units of the DNNP or the DNNP overall. For example, we understand that $105.2 of non-capital costs were incurred between 2020-2022 related to DNNP preliminary planning and preparation costs.

b) Please further explain why there are no OM&A costs included in the Unit 1 RQE. As part of the response, please provide the amount of OM&A costs that are expected to be incurred in support of Unit 1 of the DNNP over the 2027-2031 rate term.

c) OPG notes that 73% percent of the estimated costs in the Unit 1 RQE meet or exceed the level of estimate accuracy corresponding to a Class 3, with the remaining 27% at Class 4. Please provide the equivalent percentages for the first unit of the DRP RQE.

d) Please provide a breakout of the common facilities costs that are included in the Unit 1 RQE. As part of the response, please show in which bundle/scope of Chart 2 these costs are recorded.

e) Using the format of Charts 3 to 10 for categorization, please add columns showing (i) the actual costs incurred to date; (ii) a description of the work complete; and (iii) a description of the work that is left to complete.

f) Please provide a detailed breakdown of the $521 million of capital funding that has been released so far related to the three other SMR units.

D2-CCC-59
Ref: Exhibit D2, Tab 4, Schedule 8, Attachment 1

Question(s):

With respect to Units 2-4 of the DNNP, please advise whether there is any potential for an off-ramp (i.e., not moving forward with the construction of the additional units). If so, please explain the timing and process whereby that decision can be made.

<u>Exhibit D3 / Tab 1 – Support Services Capital</u>

D3-CCC-60
Ref: Exhibit D3, Tab 1, Schedule 1, p. 9

Preamble:

3.1.2 DNNP Operational Readiness Technology Projects

OPG is investing in digital technologies to ensure operational readiness for the DNNP facility. As a newly built asset, the DNNP facility provides an opportunity to design and integrate a modern suite of technology from the start, efficiently addressing operational needs and taking advantage of modular design and open architecture for the core systems.

In 2023, OPG undertook a comprehensive request for proposal process to select an EAM solution system for managing the lifecycle of physical assets for the DNNP facility. The SAP S/4HANA solution was selected based on the system's ability to deliver a streamlined, automated approach to asset management. The platform offers advanced capabilities that are expected to provide the necessary asset performance and ensure compliance with regulatory standards.

Additionally, this portfolio includes other technologies to support functions such as engineering modeling and the digitalization of plant operations, as well as tools for areas such as work protection, chemistry and radiation protection. This new suite of technology and systems will support the DNNP facilities' distinct operating model, including a streamlined workforce plan. These technologies are a prerequisite for operating the assets safely, reliably, efficiently and in compliance with regulatory requirements when Unit 1 comes online in 2030.

Question(s):

Please explain why, despite being described as a project that specifically addresses the needs of the DNNP facility and its distinct operating model, the DNNP Operational Readiness Technology Projects are not included as a part of the DNNP facility spending.

D3-CCC-61
Ref: Exhibit D3, Tab 1, Schedule 1, p. 15
Exhibit D3, Tab 1, Schedule 2, p. 5
Exhibit H1, Tab 1, Schedule 1, p. 49

Preamble:

OPG notes that "excluding undeveloped land, the expenditures for the purchase and renovation of the CHQ was $190.8M."

OPG also notes that the there is a separate project ($27.2M) to increase the capacity of CHQ parking.

OPG recorded $7M in the Clarington Corporate Campus Deferral Account related to work on the Clarington Corporate Campus project prior to the termination of the project. The Company seeks recovery of this balance (plus interest) in the current proceeding.

Question(s):

a) Please provide the total capital cost of the purchase (inclusive of the undeveloped lands) and renovation of the CHQ and discuss the treatment of the undeveloped land from a ratemaking perspective.

b) Once the parking expansion is included in the total cost, based on most recent estimates, please provide the total capital cost of the CHQ-related projects that will be recovered from ratepayers.

c) Please provide a detailed breakdown of the Clarington Corporate Campus-related costs that were written-off ($7M) and recorded in the Clarington Corporate Campus Deferral Account.

D3-CCC-62
Ref: Exhibit D3, Tab 1, Schedule 1, pp. 11-12
Exhibit D3, Tab 1, Schedule 2, Table 1

Question(s):

a) With respect to the Asset Suite 9 Project, please confirm or correct the following:

i. The project cost was $37.8M
ii. The project went into service in December 2023
iii. The asset will have been in use for a period of approximately 5 years prior to being replaced.

b) Please highlight which project reflected in the evidence will replace the Asset Suite 9 enterprise system. As part of the response, please provide the capital costs and in-service date(s) associated with the project that will replace the Asset Suite 9 system. If there is no replacement project set out in the evidence, please explain.

<u>Exhibit E1 / Tab 1 - Regulated Hydroelectric Production Forecast and Methodology</u>

E1-CCC-63
Ref: Exhibit E1, Tab 1, Schedule 1, pp. 6-7

Preamble:

OPG’s hydroelectric outages are generally planned to conduct the following:

- Refurbishment, redevelopment, or concrete work

- Preventative maintenance
- Condition-based maintenance
- Inspection and testing

In addition to regularly scheduled maintenance outages, refurbishment and overhaul work is planned at select hydroelectric facilities (details on refurbishment projects are provided in Ex. D1-1-2). These major planned outages are accounted for in the 2027 test year production forecast, including anticipated incremental production increases.

Question(s):

a) Please provide the hydroelectric production forecast for the years 2028 to 2031.

b) For each year from 2016 to 2031, please quantify the hydroelectric production lost or forecast to be lost as a result of planned outages.

c) For each year from 2016 to 2031, please quantify the increase in production capacity achieved or forecast to be achieved by OPG.

d) For each year from 2016 to 2025, please quantify the lost production due to SBG.

Exhibit E1 / Tab 2 - HIM, SBG, MRP and MWP

E1-CCC-64
Ref: Exhibit E1, Tab 2, Schedule 1, p. 2

Preamble:

OPG is also seeking the approval to eliminate the sharing of HIM revenues above the threshold established in Ex. G1-1-1 as described in Section 5.0. This proposal is supported by a Market Surveillance Panel ("MSP") recommendation and is detailed in OPG's SBGVA Study as an outcome of one of the studied options. The proposed removal of HIM revenue sharing maintains OPG's incentives across all market outcomes to the benefit of ratepayers.

Question(s):

a) Please provide the existing HIM threshold and the proposed new HIM threshold.

b) Please confirm that, to date, OPG has never exceeded the HIM threshold, such that there has never been sharing of HIM revenues above the threshold. If not confirmed, please provide details around periods where OPG exceeded the HIM threshold.

c) Please confirm that 50/50 sharing of HIM revenues above the threshold does not eliminate OPG's incentive to shift production.

d) Please describe any situation since the implementation of the HIM and the related threshold where OPG failed to shift production because of 50/50 sharing of the incentive above the threshold, where it would have shifted production had there been no sharing of the incentive.

e) Is it OPG's position that there is no obligation on it to manage production in the most economically efficient manner for its customers, regardless of a separate incentive to do so and even if OPG's costs to do so are covered?

<u>Exhibit E1 / Tab 2 – Nuclear Production Forecast and Methodology</u>

E2-CCC-65
Ref: Exhibit E2, Tab 1, Schedule 1, p. 4

Preamble:

Concurrently, during the same Unit 2 Darlington PMS replacement outage in 2027, OPG will execute the Darlington Unit 2 Turbine Control and Auxiliary Systems Upgrade project that was deferred from 2025 to support grid reliability and manage resource constraints during concurrent nuclear outages.

Question(s):

a) At Exhibit 2, Tab 1, Schedule 2, p. 2, OPG notes that the total outage related to the PMS and Turbine Control and Auxiliary Systems upgrade project for Unit 2 in 2027 is

316.5 days, and includes the outage related to the VBO for unit 2. How long would the outage be if only the PMS and the VBO were being conducted in 2027, had the Turbine Control and Auxiliary Systems upgrade project been completed in 2025 as originally planned?

b) What was the incremental net revenue earned by OPG as a result of avoiding the planned Turbine Control and Auxiliary Systems upgrade project in 2025?

Exhibit F1 / Tab 2 – Regulated Hydroelectric Base OM&A

F1-CCC-66
Ref: Exhibit F1, Tab 2, Schedule 1, pp. 3-4

Preamble:

2023 Actual versus 2022 Actual

Actual Base OM&A costs in 2023 were $236.5M, which was $21.0M or 10% higher than 2022 actual amount of $215.5M. All regulated hydroelectric organizations were impacted by higher labour cost escalation in 2023 reflecting collective bargaining process outcomes including as a result of Bill 124, as discussed in Ex. F4-3-1.

The reportable variances by category of expenses are as follows and are inclusive of the aforementioned higher labour cost escalation, with additional drivers of variance identified below where applicable:

- Operations and Maintenance ($17.0M or 12% increase):
- Operations ($2.5M or 10% increase): no other reportable variance
- Maintenance ($14.4M or 12% increase): due to higher maintenance costs primarily at R.H. Saunders GS and Sir Adam Beck 1 GS and Sir Adam Beck 2 GS due to environmental remediation (e.g., lead paint and asbestos removal), storm response clean-up, and additional joint works expenditures (see Ex. A1-4-2).
- Integrated Fleet Management ($3.7M or 82% increase): due to increased staffing levels in security, and training to support increased work program and address training backlogs.

- Enterprise Projects ($1.0M or 51% increase): due to higher staffing levels to support the increased regulated hydroelectric project portfolio.

Question(s):

When were the environmental remediation, storm response clean-up, and additional joint works expenditures completed?

Exhibit F1 / Tab 3 - Regulated Hydroelectric Project OM&A

F1-CCC-67
Ref: Exhibit F1, Tab 3, Schedule 1, p. 1

Preamble:

The OM&A projects within the regulated hydroelectric portfolio are largely sustaining expenditures for repairs and maintenance, including turbine-generator overhaul projects and projects related to aging civil infrastructure. OPG defines a project (whether capital or OM&A) as a temporary, unique endeavour undertaken outside the routine base activities of the normal work program.

Question(s):

a) Please provide the forecast hydroelectric Project OM&A budgets from 2028 to 2031.

b) How much, if any, of the proposed 2027 Project OM&A is eligible for the CRVA?

Exhibit F1 / Tab 4 – Regulated Hydroelectric Gross Revenue Charge and Other Water Agreement Costs

F1-CCC-68
Ref: Exhibit F1, Tab 4, Schedule 2, p. 1

Preamble:

The GRC is directly dependant on energy production and year-over-year GRC variances result from production impacts (primarily unit outages, water conditions, and market conditions, see Ex. E1-1-1 and Ex. E1-1-2). For historical periods, GRC is based on the actual energy production. GRC forecasts are calculated based on the energy production forecast described in Ex. E-1-1-1. The differences between actual and forecast production that are attributable to changes in natural water conditions will be captured in the Hydroelectric Water Conditions Variance Account. The account applies to 27 regulated hydroelectric plants, located on nine river systems (see Ex. E1-1-1, Appendix 1 and Ex. H1-1-1). Changes in GRC associated with these energy variances are included in determining the account balance (see Ex. H1-1-1).

Question(s):

Please confirm that differences in GRC caused by differences in unit outages and market conditions are not captured in any variance account, and OPG is not proposing to capture such impacts in a new or existing variance account.

Exhibit F1 / Tab 5 - Regulated Hydroelectric Purchased Services OM&A

F1-CCC-69
Ref: Exhibit F1, Tab 5, Schedule 1, p. 1, Chart 1

Preamble:

Total OM&A purchased services expenditures for all contactors for the historical period (2016-2024) was $57.1M in 2016, $53.2M in 2017, $57.1M in 2018, $56.5M in 2019, 49.9M in 2020, $64.7M in 2021, $78.3M in 2022, $80.2M in 2023, and $71.4M in 2024. For OM&A purchased services where costs are allocated to both the regulated and non-regulated facilities within Renewable Generation (such as work centers), only the amounts allocated to regulated hydroelectric facilities have been included (details on OPG's cost allocation methodology are described in Ex. F3-1-4 and Ex. F1-2-1). The average annual OM&A purchased services for the regulated hydroelectric facilities for all contractors over the period of 2016-2024 was $63.1M.

Question(s):

a) What are the budgeted OM&A purchased services expenditures for 2025, 2026 and 2027?

b) How can the contracts in chart 1 be sole sourced because they were less then $500,000, when the chart is supposed to be contracts in excess of $20M?

c) What was the average number of separate contracts/providers per year?

<u>Exhibit F2 / Tab 1 – Nuclear Business Planning and Benchmarking</u>

F2-CCC-70
Ref: Exhibit F2, Tab 1, Schedule 1, Attachment 2

Question(s):

Please advise whether OPG completes a nuclear benchmarking report each year. If so, please file the 2025 nuclear benchmarking report assuming it has been completed.

F2-CCC-71
Ref: Exhibit F2, Tab 1, Schedule 1, Attachment 4
EB-2020-0290, Exhibit F2, Tab 1, Schedule 1, Attachment 5

Question(s):

a) Please explain why ScottMadden's 2018 study (filed in EB-2020-0290) used EUCG data starting in 2009 and now, in its 2025 study, it uses EUCG data starting in 2006.

b) Please advise whether using the same starting point for the EUCG data as previously applied (i.e., 2009 and now extending to 2023) in the current study changes the outcome of ScottMadden's analysis. If so, please provide the revised results from that analysis.

c) Please explain, and provide the detailed reasons for, the very significant increase in the base adjustment for CANDU reactor type ($539M) relative to the 2018 study. As part of the response, please also explain the difference between the $250M adjustment for CANDU reactor type shown at page 5 of Exhibit F2, Tab 1, Schedule

1, Attachment 5 in EB-2020-0290 and the value of $284M shown in footnote 3 of the current study. If there was a subsequent version of the ScottMadden study filed in EB-2020-0290 after the filing of the pre-filed evidence, please provide a reference to where that study can be located on the EB-2020-0290 record.

d) Please explain, and provide the detailed reasons for, the significant decrease in the base adjustment for average unit age ($346k) relative to the 2018 study ($77k).

e) With respect to the unit age adjustment, please advise whether unit age resets to zero after refurbishment. If not, please explain why.

f) With respect to the additional "annual factor" adjustment to the Darlington refurbishment cost, please explain why that was not applied in the previous 2018 study.

g) Please advise whether ScottMadden believes that the additional "annual factor" adjustment that captures the proportion of total generating costs that are refurbishment-related would have improved its 2018 study. As part of the response, please provide the quintile that OPG would have been in using the same data as the 2018 study and the same methodologies that were applied in the 2018 study with the only change being the inclusion of the new "annual factor" adjustment.

h) Please provide the directional impact on Darlington's TGC/MWh of applying an adjustment for site capacity (which was not actually applied in the study). As part of the response, please further explain the "complex adjustment to generation" that is required to allow for a site capacity adjustment to be used in the overall model.

i) Please provide the charts on pages 4, 11 and 13 in tabular format. As part of the table, please provide both quartile and quintile values. Separate from the table, please provide the detailed calculations supporting each of the quartile and quintile values.

j) Please provide revised versions of the charts on each of pages 4, 11 and 13 that overlay lines showing quintiles.

k) To the extent that 2024 actual information is available for OPG and the peer group nuclear plants, please file an updated study based on the 2022-2024 historical period using ScottMadden's proposed approach for normalization and benchmarking.

l) Please provide separate tables for each of Darlington and Pickering that shows the benchmarked results in dollars and the associated quintile placement based on the following:

i. 2018 study
   1. No normalization adjustments
   2. Normalized for technology type and unit age
   3. Normalized for technology type, unit age and refurbishment
   4. Normalized for technology type, unit age, refurbishment and outages

ii. 2025 study (2021-2023 average)
   1. No normalization adjustments
   2. Normalized for technology type and unit age
   3. Normalized for technology type, unit age and refurbishment
   4. Normalized for technology type, unit age, refurbishment and outages

iii. 2025 updated study (2022-2024 average if available)
   1. No normalization adjustments
   2. Normalized for technology type and unit age
   3. Normalized for technology type, unit age and refurbishment
   4. Normalized for technology type, unit age, refurbishment and outages

F2-CCC-72

Ref: Exhibit F2, Tab 1, Schedule 1, Attachment 5
EB-2020-0290, Exhibit F2, Tab 1, Schedule 1, Attachment 6

Question(s):

a) Please provide the number of OPG purchased services-related FTEs that were excluded from the study.

b) Please further explain why a comparison of Purchased Service-related FTEs between OPG and the peer group was possible in the previous study (2020) and is no longer possible.

c) Please advise whether IT-related FTEs are included in the current study.

d) Please provide the detailed calculations, and explanations, with respect to the "work week" normalization and the "reactor count" normalization in the current study. Please explain any differences in the methodology applied in the current study relative to the previous study.

e) Please further explain Appendix C in the current study. More specifically, please explain how the FTE ratio was determined.

f) Please explain the main drivers for the difference between the current benchmarked OPG FTEs (4,458) and the previous benchmarked OPG FTEs (5,016).

g) Please explain the main drivers for the difference between the current benchmarked peer FTEs (4,913) and the previous benchmarked peer FTEs (5,255).

<u>Exhibit F2 / Tab 2 – Nuclear Base and DNNP Operational Readiness OM&A Costs</u>

F2-CCC-73
Ref: Exhibit F2, Tab 2, Schedule 1, Table 1a

Question(s):

a) With respect to the Pickering base OM&A costs proposed for recovery for the 2027-2030 period ($8.1M to $24.6M), please further explain the rationale for those costs in the context that the station is offline during that period.

b) Please provide a breakout of the detailed operations and project support cost categories (e.g., enterprise engineering, integrated fleet management, etc.) for 2020-2031 as between Darlington and Pickering.

F2-CCC-74
Ref: Exhibit F2, Tab 2, Schedule 1, Table 2

Question(s):

Please provide a breakout of the base OM&A by resource type for the 2020-2031 period between Darlington and Pickering.

Exhibit F2 / Tab 3 – Nuclear Project OM&A Costs

F2-CCC-75
Ref: Exhibit F2, Tab 3, Schedule 3, Table 4

Question(s):

For each unallocated portfolio project shown in Table 4, please provide a detailed description of the project and the estimated cost per year over the duration of the project.

Exhibit F2 / Tab 4 – Nuclear Outage OM&A Costs

F2-CCC-76
Ref: Exhibit F1, Tab 1, Schedule 1, Table 1

Preamble:

The evidence sets out the proposed Outage and Cyclical maintenance costs planned by OPG from 2027 to 2031.

Question(s):

a) Please describe what happens when a planned outage is avoided or deferred, i.e. are the planned outage costs entirely obviated?

b) Please confirm that the scope and timing of outages and cyclical maintenance included in this category of cost are defined by regulatory requirements, and that neither the scope nor the timing of either can be changed without regulatory approval. If not confirmed, please split the costs for the 2027 to 2031 period included on Table 1 between costs relating to work that the scope and timing of which is dictated by regulatory requirements, and work that the scope and timing of which is determined by OPG.

c) How much outage OM&A was included on a forecast basis for the Darlington Unit 2 Turbine Control and Auxiliary Systems Upgrade originally scheduled for 2025?

d) How much outage OM&A is included in the 2027 forecast for the Darlington Unit 2 Turbine Control and Auxiliary Systems Upgrade originally scheduled for 2025?

Exhibit F2 / Tab 5 – Nuclear Fuel

F2-CCC-77
Ref: Exhibit F2, Tab 5, Schedule 1, pp. 2-3, 10-12

Question(s):

a) Please provide a comparison, in the same format as shown in Chart 1 (including the attribution factors for the variances), of the actual nuclear fuel bundle costs for the 2017-2021 period and the forecast provided in EB-2020-0290.

b) Please provide a comparison, in the same format as shown in Chart 1 (including the attribution factors for the variances), of the actual nuclear fuel bundle costs for the 2017-2021 period and the actual costs / updated forecasts for the 2022-2026 period.

c) Please provide an expanded version of Chart 4 (Uranium Spot Prices) that extends the historical period to at least 2017 (or prior if OPG has that information readily available).

d) Please discuss which aspects of the nuclear fuel costs (i.e., Uranium concentrate, Uranium conversion, and manufactured fuel bundles) are impacted by commodity cost volatility.

e) With respect to the Uranium Concentrate Pricing Provisions and Fuel Contracts:

   i. Please expand chart 3 to include the pricing mechanism associated with those term contracts.
   ii. Please further explain the extent to which fixed pricing contracts are used (including the percentage of total purchases).
   iii. Please provide further details regarding base-escalated arrangements. As part of the response, discuss whether there is a difference between the "escalator formulas" applied and inflation index escalators.
   iv. Please explain the need for spot purchases in the context of the known production levels.

<u>Exhibit F2 / Tab 6 – Nuclear Purchased Services OM&A</u>

F2-CCC-78
Ref: Exhibit F2, Tab 6, Schedule 1, p. 1

Preamble:

As detailed in Ex. F2-2-1, Section 3.1, OM&A purchased services represent the costs of specialized external services, primarily for construction and maintenance services supporting work programs. An overview of OPG's procurement processes is presented in Ex. F3-3-1. Total OM&A purchase services expenditures for all contractors for the historical period (2020-2024) was $247.6M in 2020, $300.5M in 2021, $255.5M in 2022, $287.4M in 2023, and $275.6M in 2024. The average annual OM&A purchased services for the regulated nuclear facilities for all contractors over the period of 2020-2024 was $273.3M.

Question(s):

a) What are the budgeted OM&A purchased services expenditures for 2025, 2026, 2027, 2028, 2029, 2030 and 2031?

b) What was the average number of separate contracts/providers per year?

Exhibit F2 / Tab 7 – Darlington Refurbishment Program OM&A

F2-CCC-79
Ref: Exhibit F2, Tab 7, Schedule 1, pp. 1-2

Question(s):

Please provide a more detailed explanation regarding the reason for, including any relevant excerpts from the EB-2020-0290 evidence, regarding the TG Execution Project and Strainer Project write-offs. As part of the response, please advise whether these write-offs are part of the recovery sought in the current proceeding (including as an offset to any credits recorded in the relevant deferral and variance accounts).

Exhibit F2 / Tab 8 – Pickering Refurbishment Program OM&A

F2-CCC-80
Ref: Exhibit F1, Tab 1, Schedule 1, pp. 1-2

Preamble:

The PRP is primarily a capital project but includes Project OM&A expenses for removal costs and volumetric low & intermediate level waste ("L&ILW") variable expenses related to disposal costs.

The removal costs are associated with the replacement of existing assets in the period in which they are incurred. They include costs associated with disassembling and removal of a component to gain access to a subcomponent to be replaced. Removal costs encompass direct execution removal activities plus any specific execution indirect cost related to the removal program. These costs have been forecasted as part of the PRP Release Quality Estimate.

Question(s):

a) Please confirm that the L&ILW variable expenses are included in the calculated nuclear liability expense. If not confirmed, please provide further explanation as to why these L&ILW costs are incremental to the costs tracked as part of the nuclear liability expense.

b) Please explain why the removal costs are considered OM&A costs and not capital costs, since they relate to the refurbishment. Please explain whether or not the removal costs involve the permanent removal of assets, or only the temporary removal of assets in order to access assets that are being replaced, with the "removed" assets ultimately being put back in place.

<u>Exhibit F3 / Tab 1 - Allocation of Support Services Costs</u>

F3-CCC-81
Ref: Exhibit F1, Tab 1, Schedule 1, Attachment 2, Table 1

Preamble:

The Hackett Group benchmarking study uses the categories of Finance, HR, ECS, IT, Procurement and Real Estate & Facilities Mgmt to benchmark OPG's corporate support costs.

Tables 1 presents OPG's corporate support costs using the categories Corporate & Technology Services, Real Estate, Supply Chain, Finance, Human Resources, and Corporate Centre.

Question(s):

a) Please recategorize Tables 1-4 so that they match the categories used by the Hackett Group in their benchmarking study, combining or disaggregating the categories in the Tables as necessary.

b) Please confirm that the benchmarking results do not account for the changes in support services costs from 2024 to 2031.

c) Please benchmark OPG's proposed 2031 corporate support costs, using forecast 2031 data as necessary.

Exhibit F3 / Tab 2 - Asset Service Fees

D2-CCC-82
Ref: Exhibit F3, Tab 2, Schedule 1, pp. 6-7

Preamble:

Joint-use Renewable Generation Assets

OPG's hydroelectric business contains both regulated and unregulated renewable generation facilities, including the Company's thermal and solar generating facilities. Certain facilities such as work centers and dams or water control structures may support both regulated and unregulated assets (Ex. D1-1-1, Section 6).

To the extent that 90% or more of aggregate station capacity, as measured by the Maximum Continuous Rating, serviced by the joint-use asset relates to the regulated facilities, the related assets are included in rate base. Joint-use assets not passing this use test are not included in regulated rate base but are subject to the ASF's charged to the regulated and unregulated renewable generation facilities based on the relative direct base OM&A of the stations that benefit from the joint-use assets. The ASF structure is otherwise the same as that used to charge for CHQ and Corporate IT assets.

Question(s):

a) Please provide the details around the amount included in rate base with respect to Joint Use assets because, while shared with non-regulated facilities, are more than 90% of the aggregate station capacity relates to regulated facilities.

b) Please provide an explanation for the increase in joint use asset costs allocated to the regulated hydroelectric business from 2016 ($0.9M) to 2027 ($12.7M).

Exhibit F4 / Tab 1 – Depreciation and Amortization

F4-CCC-83
Ref: Exhibit F4, Tab 1, Schedule 1, pp. 10-11

Question(s):

a) For each of the plant accounts listed below, please provide a table that shows the depreciation expense for 2027-2031 related to the asset account using the current average service life and the depreciation expense for 2027-2031 related to the asset account using the updated average service life:

   i. Pickering and Darlington – Security and Other Fencing
   ii. Pickering and Darlington – Nuclear Exciters
   iii. Hydroelectric – Gates, Stoplogs, and Operating Mechanisms
   iv. Hydroelectric – Station Service Electrical Equipment
   v. Hydroelectric – Electronic Security Systems

b) Please provide additional details that support the basis for an initial 60-year useful life for an SMR unit.

c) Please provide additional details supporting the EOL date (December 31, 2070) for Pickering Units 5-8.

Exhibit F4 / Tab 2 – Taxes

F4-CCC-84
Ref: Exhibit A2, Tab 2, Schedule 1, p. 5
Exhibit F4, Tab 2, Schedule 1, pp. 19-20

Preamble:

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

Question(s):

a) Please confirm CCC's understanding that the value of the proposed CEITCs are, if implemented, going to be passed through to customers on a 100% basis through the application of the credits as capital contributions against the related investments and through the tracking of the related revenue requirement reductions in variance accounts. If not confirmed, please explain how OPG proposed to allocate the value of the proposed credits between itself, DNNP and customers.

b) In the circumstance that the refundable CEITC legislation is implemented, please provide a detailed estimate of the value of this tax credit on a revenue requirement basis for each year of the 2027-2031 period.

c) Please further explain the interaction between the CEITC and the CCR proposal. More specifically, if the CEITC rebate is approved will there be a credit to ratepayers associated with the CCR amounts collected during the 2027-2031 period?

d) If the CEITC legislation is approved while the current proceeding is ongoing, please provide OPG's view on implementing that rebate for ratemaking purposes as an application update.

<u>Exhibit F4 / Tab 3 – Compensation and Benefits</u>

F4-CCC-85
Ref: Exhibit F4, Tab 3, Schedule 1, pp. 5, 17, 21, 30-31, 37-39

Question(s):

a) For the 2027-2031 period, please provide the assumptions applied with respect to wage/compensation escalation for each of the next Society (January 2026) and PWU (April 2027) contracts that are reflected in the application.

b) Please discuss whether, at the time of filing the interrogatory responses, collective bargaining with the Society was completed for 2026. If so, please provide the wage/compensation escalation established in the relevant agreement. If not yet completed, please provide an update on the expected timing of the completion of collective bargaining.

c) OPG notes that it hired approximately 60% of term employees to regular positions in 2024. By the end of 2026, there will be substantially no term employees. Please further discuss the remaining 40% of term employees and whether they have also been hired on a regular basis or have otherwise left the company. As part of the response, please discuss whether the Company still has the right/ability under the relevant collective agreements to hire term employees to address shorter term needs.

d) With respect to Figure 4a:

   i. Please confirm that only the "Mgmt-Supervisory" category includes employees that have direct reports/supervisory responsibilities.

   ii. If other categories of FTEs include employees with supervisory responsibilities, please provide a breakout of the supervisors/managers in each of the other categories of FTEs.

   iii. Please advise whether there are any other categories of OPG's employees that are not reflected in this figure. If so, please update the figure to reflect those employees.

e) With respect to Figure 4b:

   i. Please confirm that only the "Mgmt-Supervisory" category includes employees that have direct reports/supervisory responsibilities.

   ii. If other categories of FTEs include employees with supervisory responsibilities, please provide a breakout of the supervisors/managers in each of the other categories of FTEs.

iii. Please advise whether there are any other categories of OPG's employees that are not reflected in this figure. If so, please update the figure to reflect those employees.

f) With respect to the salary adjustments for performance-based merit increases, please explain how those increases have been estimated and forecast for the 2027-2031 period. As part of the response, please provide the detailed assumptions made and the dollar value of the performance-based merit increases that are included in the costs proposed for recovery during the test period.

g) With respect to management staff, please further discuss the statement that the "Board of Directors' approved salary band adjustments to more closely align OPG's midpoint salaries with its peers, with the aim of gradually closing the gap to the 50th percentile." As part of the response, please provide an illustrative example of this effort for a sample management role.

h) Please provide the detailed methodology, and underlying calculation, supporting the annual overtime budget estimate for the 2027-2031 period. As part of the response, please discuss any changes relative to the overtime forecasting approach applied in EB-2020-0290.

F4-CCC-86
Ref: Exhibit F4, Tab 3, Schedule 1, Attachment 1

Question(s):

Please provide a revised version of Appendix 2-K for the Nuclear Facilities (excluding DNNP LP) that shows the following:

i. A breakout of executives from the management category for both the FTE count and all categories of compensation.
ii. A breakout of salary from incentive pay for each category of employee.
iii. A breakout of total compensation between capital and OM&A costs.

F4-CCC-87
Ref: Exhibit F4, Tab 3, Schedule 1, Attachment 2

Question(s):

Please provide a revised version of Appendix 2-K for the DNNP LP that shows the following:

i. A breakout of executives from the management category for both the FTE count and all categories of compensation.
ii. A breakout of salary from incentive pay for each category of employee.
iii. A breakout of total compensation between capital and OM&A costs.

F4-CCC-88
Ref: Exhibit F4, Tab 3, Schedule 1, Attachment 3

Question(s):

Please provide a revised version of Appendix 2-K for the Hydroelectric Facilities that shows the following:

i. A breakout of executives from the management category for both the FTE count and all categories of compensation.
ii. A breakout of salary from incentive pay for each category of employee.
iii. A breakout of total compensation between capital and OM&A costs.

F4-CCC-89
Ref: Exhibit F4, Tab 3, Schedule 1, Attachments 1-3

Question(s):

Please provide a revised version of Appendix 2-K for the combined regulated business (i.e., all of Nuclear, DNNP LP, and Hydroelectric FTEs and compensation combined) that has all the same information as in the pre-filed Appendix 2-K and also includes:

i. A breakout of executives from the management category for both the FTE count and all categories of compensation.
ii. A breakout of salary from incentive pay for each category of employee.
iii. A breakout of total compensation between capital and OM&A costs.

F4-CCC-90

Ref: Exhibit F4, Tab 3, Schedule 1, Attachment 2
Exhibit F4, Tab 3, Schedule 1, Attachment 3

Question(s):

Please explain the linkage between the Compensation Philosophy & Peer Groups study (Attachment 2) and the Total Compensation Benchmarking study (Attachment 3). As part of the response, please advise whether the peer group recommendations from Attachment 2 are applied in Attachment 3. In the situation that there are differences between the peer group recommendations, please explain the reason for those differences.

F4-CCC-91

Ref: Exhibit F4, Tab 3, Schedule 1, Attachment 2, p. 17
Exhibit F4, Tab 3, Schedule 1, Attachment 3, pp. 14-18

Preamble:

Pages 14 to 18 of the WTW Study provide a summary of results based on various comparisons between OPG and the peer group. The results are provided in percentages that show the difference between OPG's compensation levels relative to the market.

Question(s):

a) Using 2024 actual compensation, please provide the dollar value associated with the percentage differential between OPG and the market, on a total remuneration basis, for each version of the benchmarking analysis (i.e., each of pages 14 to 18 of the study) broken out between PWU, Society, Management and OPG Total. As part of the response, please provide the detailed calculation showing how the impact of OPG's compensation relative to the market (as reflected in percentage terms) is converted to a dollar figure.

b) Using OPG's forecast compensation for each year during the 2027-2031 test period, please provide the dollar value associated with the percentage differential between OPG and the market, on a total remuneration basis, for each version of the benchmarking analysis (i.e., each of pages 14 to 18 of the study) broken out between PWU, Society, Management and OPG Total. As part of the response, please provide the detailed calculation showing how the impact of OPG's compensation relative to the market (as reflected in percentage terms) is converted to a dollar figure.

c) Please provide a revised version of the "Impact of Pension, Benefits & PWU Terms Incumbent Changes since April 2024" results (page 18) inclusive of the Hydro One share grants.

d) Please provide revised summary results of the Total Compensation Benchmarking Study applying each of the following changes to the methodology:

   i. Exclude the 7.5% adjustment for non-authorized nuclear operations roles.
   ii. Reflect a 50%/50% weighting of public and private peers, which was the most recent methodology.
   iii. Reflect a 25%/75% weighting of public and private peers (as recommended at Attachment 2, p. 17).
   iv. Reflect a 50%/50% weighting of public and private peers and exclude the 7.5% adjustment for non-authorized nuclear operations roles.
   v. Reflect a 25%/75% weighting of public and private peers (as recommended at Attachment 2, p. 17) and exclude the 7.5% adjustment for non-authorized nuclear operations roles.

   Please provide the requested revised summary results inclusive of the Hydro One Share Grants and based on a comparison of Nuclear Authorized at the 50th percentile.

F4-CCC-92
Ref: Exhibit F4, Tab 3, Schedule 1, Attachment 3, pp. 6-7, 20, 35

Question(s):

a) Please further explain the 7.5% adjustment for non-authorized nuclear operations roles at select career levels. As part of the response, please provide the number of

OPG incumbents (and the percentage of incumbents relative to total) that are applied this adjustment.

b) WTW notes that “[o]ther one-time lump-sum awards (whether in cash or shares) are not captured in WTW’s compensation surveys which could potentially understate the market results.” Please explain what is included in the long-term incentives (as set out in the market definition data at p. 7 of the report) and how it differs from the Hydro One share grants that are provided to some of OPG’s employees.

e) Please provide the percentage of the total peers in the benchmarking study that apply a 1.5x overtime rate.

F4-CCC-93
Ref: Exhibit F4, Tab 3, Schedule 2, pp. 9, 12-13

Question(s):

a) Please further explain the proposed increase in the longer-term salary escalation rate to inflation plus 0.75% (relative to inflation plus 0.5%). As part of the response, please discuss the relationship between the assumption used for pension and OPEB determination purposes and the salary escalation applied for the 2027-2031 period. Please also provide the impact on pension and OPEB costs (for all business units) for the 2027-2031 period of a 0.25% increase in the salary escalation rate.

b) Please further explain the rate of return assumption (6.25%) for the pension fund asset values in the context of the average actual 7% return between 2020-2024. Please provide the 2027-2031 impact on pension and OPEB costs (for all units) of using a 7% rate of return assumption for pension fund asset values (instead of 6.25%).

c) Please advise whether the Canadian Institute of Actuaries has provided its final endorsement of the 2024 Mortality Improvement Scale.

<u>**Exhibit F4 / Tab 4 – Centrally-Held Costs**</u>

F4-CCC-94

Ref: Exhibit F4, Tab 4, Schedule 1, p. 6

Preamble:

Second, with the last unit returning from refurbishment in 2026, OPG plans to purchase nuclear BI insurance for Darlington beginning in 2027 in order to mitigate the potential loss of earnings in the event of physical damage to the station from a nuclear peril. Standard BI policies exclude nuclear risks, making specialized coverage necessary for any such protection. While it has not historically procured this coverage, OPG considers this to be an appropriate time to add this product as part of its risk management practices in view of the company's evolving financial profile. OPG is facing increased funding needs to meet the forecast capital expenditures, and uninterrupted revenues from electricity generation at Darlington will be a critical source of such cashflow. Should an insurable BI event occur, having the appropriate insurance coverage will be important to mitigating the impact to OPG's funding profile and therefore credit ratings.

Question(s):

Please explain how BI insurance will operate in the event of an insurable event. For example, how would the insurance operate in the event that OPG lost production at a DRP unit in 2029 as a result of an insurable event? What counts as an insurable event?

F4-CCC-95
Ref: Exhibit F4, Tab 4, Schedule 1, p. 10, Table 5b

Preamble:

IESO non-energy costs are charges applied to the withdrawal of energy from the IESO-controlled grid. These charges include transmission charges, the debt retirement charge up to April 2018, the rural and remote electricity rate protection charge, the IESO administration fee, uplift charges, and the Global Adjustment. These charges are not discretionary and apply to all energy withdrawals from the IESO-controlled grid. The charges are directly assigned to the specific regulated facilities.

Question(s):

a) How does OPG forecast IESO non-energy charges?

b) Table 5B exhibits some apparently large variations between OEB approved and actual IESO non-energy charges; what is the driver behind this variances, and are these variances trued up in some fashion, i.e. through a variance account, or are they variances that OPG bears the risk for?

<u>Exhibit G1 / Tab 1 – Regulated Hydroelectric Other Revenues</u>

G1-CCC-96
Ref: Exhibit G1, Tab 1, Schedule 1, p. 9

Preamble:

OPG's HIM forecasting has been updated to incorporate features of the redesigned HIM in the Renewed Market as described in Ex. E1-2-1. These include the shift from monthly to daily averaging, the replacement of the Hourly Ontario Energy Price with LMP, and the introduction of a Day-Ahead HIM. While OPG's models reflect the design of the Renewed Market, forecasting HIM net revenues is subject to uncertainties.

The expected integration of battery energy storage facilities between 2025 and 2028 is expected to put downward pressure on LMP price spreads, reducing OPG's opportunities to earn HIM net revenues. The outcomes of the first few months of the Renewed Market are not sufficient to serve as a dependable model input on account of high month-to-month variability.

Question(s):

Given OPG's assertion that "the outcomes of the first few months of the Renewed Market are not sufficient to serve as a dependable model input", please explain further why OPG believes it is appropriate to both: (i) fix the HIM incentive forecast for rate setting purposes for the IR term based on the 2027 forecast; and (ii) eliminate 50/50 sharing above the forecast threshold, a mechanism design to protect customers against forecast uncertainty.

<u>Exhibit G2 / Tab 1 – Nuclear Non-Energy Revenues</u>

G2-CCC-97
Ref: Exhibit G2, Tab 1, Schedule 1, pp. 6-7

Preamble:

Direct costs for heavy water processing services are for estimated incremental direct labour costs attached to processing heavy water for Bruce Power at the TRF and direct labour (e.g., handling, testing, packaging) and other costs (e.g., shipping) attached to the provision of other services (e.g., loans, swaps, upgrading) to third parties.

Question(s):

a) How does OPG establish the price it charges to 3rd parties, including Bruce Power, for Heavy Water processing?

b) Please explain if and how the D2O Storage Facility is used to facilitate Heavy Water Processing.

c) To the extent that the D2O Storage Facility is used to facilitate Heavy Water Processing, please explain if and how the costs of the D2O Storage Facility are allocated to the costs recovered from third parties for heavy water processing.

d) Please provide a fully allocated pricing analysis of the heavy water processing service.

Exhibit G2 / Tab 2 – Bruce Generating Stations Revenues and Costs

G2-CCC-98
Ref: Exhibit G2, Tab 2, Schedule 1, Table 1

Preamble:

The noted tables compare the OEB-approved Bruce Lease related revenues and costs against the actual/budgeted revenues and costs from 2020 to 2026.

Question(s):

a) Please confirm that the entire net differential between the OEB forecast net revenue associated with the Bruce lease (i.e. as set out in Table 1) is subject to true up through the Bruce Net Lease Variance Account. If not confirmed, please explain which aspects of the net revenue are not ultimately trued up to actual through the account.

b) What incentive, if any, does OPG have to maximize the net revenue impact of the Bruce lease on customers?

<u>Exhibit H1 / Tab 1 – Deferral and Variance Accounts</u>

H1-CCC-99
Ref: Exhibit H1, Tab 1, Schedule 1, p. 10

Preamble:

The Ancillary Services Net Revenue Variance Account was originally established by O. Reg. 53/05. It was subsequently approved by the OEB in EB-2007-0905 and has been approved in all subsequent OPG applications. This account recognizes that ancillary services revenues are difficult to forecast accurately, with variability in actual ancillary revenues reflecting changing demand and system operating requirements.

Question(s):

Given the stated issues in forecasting ancillary services revenue as the reason for the account, is OPG opposed to maintaining the nuclear subaccount open in case the current forecast turns out to be inaccurate?

H1-CCC-100
Ref: Exhibit H1, Tab 1, Schedule 1, pp. 19-20

Question(s):

Please provide a detailed calculation supporting the referenced non-capital costs for the 2027-2031 period for the Hydroelectric CRVA.

H1-CCC-101
Ref: Exhibit H1, Tab 1, Schedule 1, pp. 38-39

Question(s):

With respect to the Nuclear Development Variance Account, please provide the year-end 2024 balance associated with potential new nuclear generation facilities other than the DNNP and describe the activities that underpin these costs.

H1-CCC-102
Ref: Exhibit H1, Tab 1, Schedule 1, p. 41

Question(s):

a) Please provide the total amount of interest (at OPG's long-term debt rate) that will be recorded in the Rate Smoothing Deferral Account over the 10-year disposition period.

b) Please provide the total amount of interest (at OPG's long-term debt rate) that will be recorded in the Rate Smoothing Deferral Account based on (i) a 3-year disposition period; and (ii) a 5-year disposition period.

H1-CCC-103
Ref: Exhibit H1, Tab 1, Schedule 1, pp. 44-45

Question(s):

Please provide a detailed breakdown of the costs recorded in the Pickering Closure Costs Deferral Account. As part of the response, please explain the reason that each of the costs was incurred.

H1-CCC-104
Ref: Exhibit H1, Tab 1, Schedule 1, pp. 44-45

Question(s):

With respect to the sale of Kipling Site, please provide the detailed calculation for each of the initial after-tax gain ($12.3M) and the subsequent gain in 2023 ($2.5M) in a format that allows comparability between these two calculations.

H1-CCC-105
Ref: Exhibit H1, Tab 1, Schedule 1, p. 50
Exhibit I1, Tab 1, Schedule 1, p. 2

Question(s):

a) Please provide the estimated cumulative earnings sharing amount for the 2022-2025 period based on most recent actuals. As part of the response, please provide the detailed calculation.

b) Please provide a detailed discussion of the estimated 4.7% ROE in 2026. As part of the response, please confirm that the estimated 2026 ROE excludes all DNNP-related expenditures.

H1-CCC-106
Ref: Exhibit H1, Tab 1, Schedule 1, p. 60

Question(s):

Please provide the proposed materiality threshold that would be applied with respect to a single "change of law" that occurs during the 2027-2031 period for the purposes of determining whether the impacts of that change would be subject to refund/recovery in the Change of Laws Deferral Account.

H1-CCC-107
Ref: Exhibit H1, Tab 1, Schedule 1, p. 65

Question(s):

Please explain the basis for the application of OPG's long-term debt rate on the Payment Amount Shaping Deferral Account in the context of the proposed recovery of the balance, through inclusion directly in the nuclear revenue requirement, in the year after the balance is recorded. Please advise whether there is any regulation/legislation that requires interest amounts to be recorded at OPG's long-term debt rate.

H1-CCC-108
Ref: Exhibit H1, Tab 1, Schedule 1, p. 72

Question(s):

Please provide a table that lists all the deferral and variance accounts that are currently in place and proposed for the 2027-2031 period and the type of interest that applies (i.e., OEB policy interest rate for DVAs, OPG's long-term debt rate, etc.).

Exhibit I1 – Determination of Payment Amounts

I1-CCC-109
Ref: Exhibit I1, Tab 3, Schedule 2, p. 5

Question(s):

Please provide a revised version of Chart 3 that shows the WAPA and residential bill impacts in a single table based on the shaping proposal.