EB-2025-0297

ONTARIO ENERGY BOARD

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

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

INTERROGATORIES

ON BEHALF OF THE

SCHOOL ENERGY COALITION[1]

A1-SEC-1
[A1] Please provide a copy of all materials provided to OPG's Board of Directors for both the development and approval of the underlying 2027-2031 budgets included in the Application.

A1-SEC-2
[A1] For each year of the plan, and for each of hydroelectric, nuclear and DNNP, please provide the total capital expenditures and in-service additions budgets, and how much of the variance in those costs would be captured by existing or proposed DVAs that are, a) mandated by O.Reg 53/05, and b) justified for any other reason.

A1-SEC-3
Please provide a copy of all third-party benchmarking analyses, studies, reports, and/or similar documents, undertaken for, by, or that include OPG, since 2021, that are not already included in this application, regarding any aspect that directly or indirectly relates to a material aspect of OPG's budget, or aspect of its regulated business.

A1-SEC-4
[A1] Please provide a table that shows all components of the proposed revenue requirement that, because of O.Reg 53/05, the OEB's usual discretion and authority is constrained. For each component, please provide, a) the specific cost in each year of the term, b) how the OEB's discretion/authority has been constrained, and c) the specific applicable provision of O.Reg 53/05.

A1-SEC-5
[A1] Please provide a table that shows, for each year between 2008 and 2031, the actual or proposed, a) base nuclear payment amounts, b) nuclear DVA payment amounts riders, c) hydroelectric base payment amounts, d) hydroelectric DVA payment amounts riders.

A1-SEC-6
[A1] Please provide a list of productivity and efficiency initiatives undertaken by OPG each year since 2022. For each, please quantify the savings, broken down by segment (nuclear and

[1] For any interrogatory which requests a revised version of a table from the evidence, consistent with the request in 1-CCC-1, please ensure that it also includes 2025 actuals.

hydroelectric) and capital and OM&A. Please provide underlying calculations, an explanation of the calculation methodology, and any assumptions made.

A1-SEC-7
[A1] Please provide a list of productivity and efficiency initiatives planned to be undertaken by OPG each year between 2027 and 2031, broken down by segment (nuclear, DNNP, and hydroelectric) and capital and OM&A. Please provide underlying calculations, an explanation of the calculation methodology, and any assumptions made.

A1-SEC-8
[A1-3-1, p.4] OPG proposed that the impact of the proposed Clean Electricity Investment Tax Credit (CEITC) be captured in the proposed CEITC Variance Account. If the impacts were to be included in revenue requirement sought for approval as opposed to a CEITC Variance Account, please provide the full impact on each aspect of the revenue requirement per year. Please provide all calculations.

A1-SEC-9
[A1-3-1, p.4] With respect to planning and preparation for potential new hydroelectric generation, how does OPG intend to handle any planning and preparation related costs incurred during the rate term?

A1-SEC-10
[A1-3-2, p.5-6] Please provide a table showing, for each year from 2027 to 2031, the difference between, a) the amount recovered (or eligible to be recovered) for hydroelectric as proposed in the current proposal, and b) the amount recovered (or eligible to be recovered) for hydroelectric under the ratemaking framework approved in EB-2016-0152. Please provide all calculations and assumptions used. Please also include, under the EB-2016-0152 framework scenario, any amounts that could be recovered through the Capacity Refurbishment Variance Account (CRVA).

A1-SEC-11
[A1-3-2, p.9] With respect to the proposed hydroelectric annual adjustment mechanism:

a. [A2-2-1, Attachment 1, p.37] Please confirm that the forecast total regulated hydroelectric production between 2028 and 2031, before SBG losses, is forecast to be: 2028: 32.7 TWh, 2029: 33 TWh, 2030: 33 TWh, 2031: 32.9 TWh.
b. Please explain why OPG did not include as a component of the 2028-2031 hydroelectric payment amount adjustment formula a mechanism to prevent the C-factor from over-recovering capital costs as a result of the forecast increase in hydroelectric production before SBG (for example. see Decision and Order (EB-2014-0116), December 29, 2025, p.28-29).
c. Please provide OPG's view on the appropriate adjustment to the 2028-2031 hydroelectric payment amount adjustment formula to eliminate any double recovery of capital costs as a result of the increase in forecast hydroelectric production.

A1-SEC-12
[A1-3-2, p.18] Please provide a full table that shows the 2027 to 2031 hydroelectric total revenue requirement (including non-capital-related revenue requirements).

A1-SEC-13
[A1-3-2, p.26] With respect to interaction between various accounts:

a. Please explain the interaction between the CRVA and the proposed tax-related accounts.
b. Please explain why the tax related impacts are not excluded from the Global Hydroelectric

Capital Variance Account (GHCVA).

A1-SEC-14
[A1-3-2, Attachments 4 and 5] With respect to the 2024 Performance Scorecards:

a. Please explain how the target for OM&A Unit Energy Cost ($/MWh) is determined.
b. Please explain how the target for OM&A Unit Energy Cost ($/MWh) promotes efficiency.
c. Please explain how the Total Generating Cost per Net MWh ($/MWh) for Nuclear is normalized.

A1-SEC-15
[A1-3-2, p.35-36] Does the proposed ESM include DNNP? If not, please explain why not?

A1-SEC-16
[A1-3-2, Attachment 1] With respect to the LEI, *Analysis of Inflation Factor Options for OPG's Regulated Hydroelectric Business* Report.

a. [p.2, 6, 16] Please confirm that LEI is recommending application of an inflation factor to historical costs that are in fact not inflating (such as depreciation and cost of capital). Please describe in detail all investigations or other work done by LEI to determine the extent to which inflation in fact increases depreciation of capital assets and cost of capital over time.
b. [p.6] Please describe and explain the interaction between a) increases in the gross revenue from the hydroelectric business due to the annual IRM adjustments to payment amounts, b) changes in the gross revenue from the hydroelectric business due to changes in units of production, c) the Gross Revenue Charge, d) application of the I-factor to the GRC, e) changes to the level of the GRC as determined by the government from time to time, and f) total factor productivity of the hydroelectric business.

A1-SEC-17
[A1-3-2, Attachment 1] With respect to the LEI, *Analysis of Inflation Factor Options for OPG's Regulated Hydroelectric Business* Report.

a. [p.11] Please describe the extent to which each of the cited precedents includes regulated hydroelectric assets. If the cited precedents include significantly less hydroelectric assets than OPG's regulated hydroelectric business, please discuss how that fact should be taken into account in assessing the relevance of each of the cited precedents.
b. [p.14] Please discuss the reasons for the volatility of capital cost indices.
c. [p.22] Please provide whatever information is available on the reasons why OPG's indicative labour cost growth has substantially exceeded AWE growth over the 22-year comparison period.
d. [p.29] Please explain why trends in the <u>value</u> of existing capital assets and the <u>value</u> of the services they provide would be relevant to the inflation impact on the <u>cost</u> of new capital assets.

A1-SEC-18
[A1-3-2, Attachment 2] With respect to the LEI, *Empirical Analysis of Total Factor Productivity Trends in the North American Hydroelectric Generation Industry* Report:

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

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

A1-SEC-19

[A1-3-2, Attachment 2] With respect to the LEI, *Empirical Analysis of Total Factor Productivity Trends in the North American Hydroelectric Generation Industry* Report:

a. [p.24] Please describe what analysis LEI did to ensure that there are no TFP trends in the data based on total MW of the generator. Please provide the TFP results if all generators with under 1,000 MW of capacity are excluded.
b. [p.25] Please explain why payments for things like SBG, HIM, ancillary services, or other revenues that represent increases in the outputs of the hydroelectric business, are excluded.
c. [p.27] Please explain what conclusions, if any, should be drawn from the fact that OPG is significantly larger than all of the peers, and its fleet is older than most of the peers. What adjustments, if any, have to be made to the peer group TFP to reflect size and age in applying the results to OPG?
d. [p.29] Please add OPG to Figure 9.
e. [p.29] What investigations, if any, did LEI carry out to determine that administration costs would not impact the TFP trend of OPG?
f. [p.35] Please confirm that the O&M input was deflated using the same inflation factor that LEI is proposing for the I-factor. If not confirmed, please explain why and assess the impact of the difference.
g. [p. 37] Please provide separate versions of Figure 14 for each of the US and Canada (OPG).

A1-SEC-20

[A1-3-2, Attachment 2] With respect to the LEI, *Empirical Analysis of Total Factor Productivity Trends in the North American Hydroelectric Generation Industry* Report:

a. [p.46] Please explain why, if the revenue of an entity (like OPG) is driven by inflation and TFP, the exogenous method is not a circular calculation.
b. [p. 50, 51] Please describe what steps, if any, were taken by LEI to confirm that the volatility in Figures 26 and 27 is the result of volatility in either weather or hydrology.
c. [p.52] Please describe how LEI has taken into account differences in operating characteristics of hydroelectric facilities, such as storage vs. run-of-the-river, flood control uses, peak demand focus, etc. To what extent, if any, is the OPG hydroelectric fleet operated in a similar manner to the hydroelectric fleets of the peer group? To what extent, if any, does the fixed and mostly inflexible production from nuclear in Ontario have an impact on the productivity of the OPG hydroelectric business?
d. [p.54] Please provide a fitted trend line for each of the capital input quantity indices in Figure 32.

A1-SEC-21

[A1-3-2, Attachment 3] With respect to the LEI, *Benchmarking the Costs of Hydroelectric Generation Companies In North America* Report:

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

b. [p.7, 19] Please explain the causal relationship between ownership and costs. What are the aspects of differing ownership (size of entity, public sector vs. private sector, type of regulation, etc.) that cause costs to be different? What investigations has LEI done to determine the nature and quantum of those causal relationships?
c. [p. 13, 21] Please explain why the independent variable "two or less active units" is used (as opposed to three, or five, for example), and why the variable is treated as binary rather than variable with the number or size of the units.
d. [p.13] Please compare the labour and non-labour components in this study with the inflation and TFP studies.
e. [p.13] Please confirm that the OM&A and Capital price indices in this study are static (point in time) numbers rather than rate of change or trend numbers.
f. [p. 13] Please provide a complete list of the independent variables tested and the reasons for their acceptance or rejection. Please provide a detailed explanation of any operating parameters (run of the river vs. storage, dispatch order, environmental restrictions, etc.) that were tested as independent variables.

A1-SEC-22
[A1-3-2, Attachment 3] With respect to the LEI, *Benchmarking the Costs of Hydroelectric Generation Companies In North America* Report:

a. [p.17] Please provide the results of this benchmarking study if environmental and regulatory costs are included.
b. [p.18] Please provide the number of plants studied that are owned by OPG (either directly or indirectly).
c. [p. 21] Please provide the results of this benchmarking study if OM&A prices are not included as an independent variable in the model.
d. [p. 25] Please provide the actual cost (OM&A and OM&A+SC) per unit of output (MWh) of each of the plants included in the study (including the size of the plants, and whether they are OPG plants, other Canadian plants, or American plants, but no other identifying features).

A2-SEC-23
[A2-2-1, Attachment 1, p.9] OPG's Business Plan notes that it expects to receive an equity injection of about $1Bn in late 2025, and that "[u]nder the anticipated terms of the equity injection, associated dividends would be in-kind during the business plan period."

a. Did the Province make the referenced equity injection?
b. What is meant by the associated dividends would be "in-kind"?

A2-SEC-24
[A2-3-1, Attachment 5, p.2] Morningstar DBRS states: "The Company is currently exploring additional credit supportive funding sources, which would reduce its debt needs."

a. Please provide details of what credit supportive funding OPG is exploring and its status.
b. Is OPG currently investigating further CIB funding? If so, please provide details of all discussions with the CIB related to potential equity and/or debt funding.

A2-SEC-25

[A2-2-1, Attachment 1] Please provide a full reconciliation between:

a. The 2025-2031 OPG nuclear and DNNP OM&A as set out in the Business Plan (A2-2-1, Attachment 1, p.34), and the OM&A included in the application (F2-1-1 Table 1a).
b. The 2025-2031 OPG nuclear and DNNP capital expenditures as set out in the Business Plan (A2-2-1, Attachment 1, p.38) and in the Application (D2-1-2, Table 1).
c. The 2025-2031 OPG support services OM&A as set out in the Business Plan (A2-2-1, Attachment 1, p.34) and in the Application (F3-1-1, Table 1).
d. The 2025-2031 OPG support services capital expenditures as set out in the Business Plan (A2-2-1, Attachment 1, p.38) and in the Application (D3-1-1, Table 1).
e. The 2025-2031 OPG centrally held OM&A costs as set out in the Business Plan (A2-2-1, Attachment 1, p.34) and in the Application (F4-4-1, Table 1).

For each reconciliation, if they are not the same, please explain all differences.

A2-SEC-26
[A2-2-1, Attachment 1] With respect to regulated hydroelectric included in the Business Plan:

a. The Business Plan includes OPG regulated hydroelectric OM&A as part of the 'Renewable Generation'. Please provide a breakdown of the Renewable Generation OM&A costs between regulated hydroelectric and non-regulated hydroelectric.
b. Based on the Business Plan OM&A costs, please provide the total regulated hydroelectric OM&A for each year between 2025-2031.
c. Please provide a full reconciliation between the 2025-2031 OPG hydroelectric capital expenditures as set out in the Business Plan (A2-2-1, Attachment 1, p.38), and the capital expenditures included in the Application (D1-1-1, Table 1). If they are not the same, please explain all differences.
d. Please provide a full reconciliation between the 2025-2027 OPG hydroelectric OM&A as set out in the Business Plan (A2-2-1, Attachment 1, p.34), and the OM&A included in the Application (F1-1-1 Table 1a). If they are not the same, please explain all differences.

A2-SEC-27
[A2-2-1, Attachment 2, p.9] The 2025-2031 Business Plan Assumptions states that "OPG also begins support of new nuclear in Saskatchewan and Alberta, and other international jurisdictions including Poland, UK, and beyond through Laurentis Energy Partners." Please explain how the revenue and costs for OPG's support for new nuclear has been incorporated into the proposed revenue requirement between 2027 and 2031, and specify the specific revenues and costs.

B1-SEC-28
Please complete the attached Excel spreadsheet.

C1-SEC-29
[C1-1-1, Attachment 1] With respect to the Concentric Energy Advisors ("Concentric"), *Common Equity Ratio Study*, for each proceeding where the authors of the Concentric report have provided expert evidence on utility cost of capital, please provide the following information regarding those proceedings, as applicable:

a. Jurisdiction
b. Date

c. Docket Number
d. Applicant
e. Client
f. Existing equity ratio
g. Author's recommended equity ratio
h. Approved equity ratio as a result of the proceeding, and how it was reached (decision or settlement)
i. Existing ROE
j. Author's recommended ROE as a result of the proceeding, and how it was reached (decision or settlement)
k. Approved ROE
l. A copy or web link to the authors written report/testimony
m. A copy or web link to the commission/regulatory decision

C1-SEC-30
[C1-1-1, Attachment 1] With respect to the Concentric Energy Advisors ("Concentric"), *Common Equity Ratio Study:*

a. Please provide the most recent S&P, DBRS, Moody's and Fitch rating reports, for each of the peer/proxy group companies.
b. Please include the full documents included in the following footnotes: 70, 72, 83, 105, 146, and 171-182.

C1-SEC-31
[C1-1-1, Attachment 1] With respect to the Concentric Energy Advisors ("Concentric"), *Common Equity Ratio Study,* please explain how, if all, Concentric considered each of the following in its assessment of OPG business risks:

a. The impact of Darlington NGS and Pickering NGS post-refurbishment on unplanned outages and other risks.
b. OPG's view that the Darlington Refurbishment Program ("DRP") came in on-time and on-budget.
c. Government of Ontario's willingness to treat DNNP separately through O.Reg 53/05.
d. Government of Ontario's support for nuclear generation.
e. Rate framework sought by OPG in this application.
f. Proposed new DVA accounts sought by OPG in this application.

C1-SEC-32
[C1-1-1, Attachment 1, p.68-69, 77] With respect to the Concentric Energy Advisors ("Concentric"), *Common Equity Ratio Study*, Concentric discusses the unique nature of OPG as a "pure-play generator" and the only one included in the peer groups.

a. In light of the unique nature of OPG as a "pure-play generator", please explain why Concentric did not include companies in its analysis that are primarily power generation, even if it is not rate regulated (i.e. independent power producers with significant contracted assets such as Boralex Inc., Northland Power Inc. Brookfield Renewable Partners L.P, and TransAlta).
b. Please undertake an analysis similar to the other peer groups in the Report for IPP companies referenced in part a. and provide a comparison of equity thickness.

C1-SEC-33
[C1-1-1] Please provide a table showing for each year between 2008 and 2026, the approved ROE included in base rates and the actual ROE (and forecast ROE for 2026) for each of, a) combined OPG, b) hydroelectric business, and c) nuclear business. Please provide full calculations for all actual ROE.

C1-SEC-34
[C1-1-1, Tables 1-5] Please provide revised versions of Tables 1-5 that show the cost of capital with the existing 45% equity ratio, and a variance analysis showing the difference as compared to the proposed equity ratio.

C1-SEC-35
[C1-1-1, Attachment 1, p.47] Please provide a copy of any analysis OPG undertook in the development, consultation or consideration, or after, of the amendments to O.Reg. 53/05 regarding the impact of concurrent cost recovery on OPG's financial metrics.

C1-SEC-36
[C1-1-1, Attachment 3, p.34] With respect to the *Initial Financing For Darlington New Nuclear Program* Report, Evidence by Cliff Inskip, is the key reason that Mr. Inskip believes "that there is a low or very low probability of a successful offering of investment grade non-recourse bonds within 12-18 months following the in-service date of the first SMR unit for the DNNP" because there will be units whose construction is in progress? Put another way, if there was only a single SMR unit to be constructed, would Mr. Inskip have come to a different conclusion.

C1-SEC-37
[C1-1-1, Attachment 3, p.39] With respect to the *Initial Financing For Darlington New Nuclear Program* Report, Evidence by Cliff Inskip, please provide copies of the material relied upon if not otherwise provided for in the evidence for items f, g, h, k, l, m, n, o, p and q.

C1-SEC-38
[C1-1-1, Attachment 3] Please provide details and a copy of any analysis that OPG undertook regarding its ability to secure debt financing for the DNNP within 12-18 months following the in-service date of the first unit.

C1-SEC-39
[C1-1-2, p.7-8] Please provide all underlying calculations used to forecast the Government of Canada Bond Rates set out in Chart 1 and 1A, and the Issuance Costs set out in Chart 2 and 2A.

C1-SEC-40
[C1-1-2, p.9] The evidence states: "The debt outstanding under the CIB facility will remain with OPG following the transfer of the DNNP facilities to DNNP LP. As discussed above, as it will no longer be associated with OPG's prescribed facilities, this debt is excluded from that attributed to OPG's regulated operations. Instead, under the expected partnership arrangements, OPG expects to credit or charge DNNP LP for the net financial impact to OPG resulting from the outstanding debt under the CIB facility beginning in 2026."

a. Please provide the details of the CIB Facility.
b. Please explain what is meant by the "net financial impact" resulting from the outstanding

CIB debt facility and how they can be a charge or credit.
c. Please provide an estimate of the potential credit or charge.
d. Are the costs, charged or credited, to DNNP LP recoverable from ratepayers, if so, please provide how and when?

D1-SEC-41
[D1-1-1, p.1] OPG notes that the average age of its hydroelectric assets is 90 years.

a. Is age of the asset the deciding factor in decisions to refurbish? Please explain.
b. Some of the Summary Business Cases refer to a Condition Assessment report. Does OPG have a means of measuring the condition of its assets, i.e. a condition assessment score? If so, please explain how it is determined.
c. For those hydroelectric capital and OM&A projects > $30M please provide the Condition Assessment report, if available, and/or a condition assessment score for each affected asset.

D1-SEC-42
[D1-1-1, Table 2] With respect to Hydroelectric capital expenditures:

a. Please provide the forecasted capital expenditures for 2017 to 2024 in the same level detail as provided in D1-1-1 Table 2.
b. Please provide the source of the provided forecast, e.g. Business Plan, OEB application, etc.

D1-SEC-43
[D1-1-2, p.16] With respect to the turbine-generator refurbishment program:

a. Is there an overriding document that lays out all of the stations requiring turbine-generator refurbishment, condition of each of the units, and a schedule for completion? If yes, please provide.
b. Please explain how OPG prioritizes turbine-generator refurbishment projects?
c. Please provide an overall schedule covering the full 2016 to 2031 period outlining the start date and in-service date for all turbine-generator refurbishment projects.
d. Please explain how OPG determines its overall and annual budgets for turbine-generator refurbishment?
e. Please provide the total cost of the turbine-generator refurbishment program.

D1-SEC-44
[D1-1-2, p.27] With respect to the station redevelopment projects:

a. Is there an overriding document that lays out all of the stations with redevelopment potential, condition of each of the units and a schedule for completion? If yes, please provide.
b. Please explain how OPG prioritizes the station redevelopment projects?
c. Please provide an overall schedule covering the full 2016 to 2031 period outlining the start date and in-service date for all station redevelopment projects.
d. Please explain how OPG determines its overall and annual budgets for station redevelopment?
e. Please provide the total cost of the station redevelopment projects/program.

D1-SEC-45
[D1-1-2, Tables 1, 2a and 2b] With respect to hydroelectric capital expenditures:

a. Please provide similar tables to D1-1-2, Tables 1, 2a and 2b, for each year between 2027 and 2031 that shows capital expenditures instead of capital additions.

b. Within each table, please group the projects as per the categories shown in D1-1-1 Table 2.

D1-SEC-46
[D1-1-2, Table 2b] With respect to the Kenora Commons, NWK Work Centre Building, with an in-service date of December 2027:

a. Is the full cost of the NWK Work Centre Building used in calculating the ASF for Regulated Hydroelectric in F3-2-1 Table 1?
b. Please provide the calculation.

D1-SEC-47
[D1-1-2, Tables 5a and 5b] Please indicate which projects in Tables 5a and 5b are Portfolio projects/Region or Non-Portfolio/Refurbishment, Redevelopment, Expansions.

D1-SEC-48
[D1-1-2, Attachment 1, Tab 20] With respect to the Business Case Summary ("BCS") for Project #84901 Northwestern Operations Work Centre Building:

a. What was the annual lease payment for the additional space?
b. Please provide evidence of the cost volatility and rate escalation associated with leasing.
c. What is the incremental cost to the project to incorporate measures to produce a net-zero building under Canada's Zero-Carbon Building Standards?
d. What are the plans for the current building?

D1-SEC-49
[D1-1-2, Attachment 1, Tab 24, p.3] With respect to the Business Case Summary ("BCS") for Project #86386 Kakabeka Falls Generating Station Redevelopment Project, which states: "Over the approximate life of 90 years for the redeveloped facility, the levelized cost of energy ("LCOE") of this alternative relative to the base case is estimated at approximately $90/MWh (2024$), including project costs to date. On a forward-looking cost basis, the LCOE of the alternative is approximately $80/MWh (2024$) relative to the base case. OPG's analysis shows that this redevelopment will provide positive economic value to the province's electricity system.":

a. Please provide the calculations for the LCOE of $90/MWh.
b. Which alternative is OPG referring to for the LCOE of $80/MWh?
c. At what LCOE does OPG consider a station redevelopment project to provide positive economic value? Please explain the basis for your answer and any underlying calculation and assumptions made.

D1-SEC-50
[D1-1-2, Attachment 1, Tab 36] With respect to the BCS for Project #87329 Dymond Machine Shop Expansion:

a. Please provide any documentation outlining how OPG determined that the lathe has reached end-of-life.
b. Please provide any documentation outlining what alternatives to replacing the lathe were investigated, e.g. obtaining external lathe services.
c. Please confirm that the purchase order has been issued.
d. Please explain what is meant by "Does not meet the requirements of the Purchased Services Agreement (PSA) with the Power Workers Union (PWU)", with respect to the status quo.

D1-SEC-51

[D1-1-2, Attachment 1, Tab 37] With respect to the BCS for Project #87356 BK2 G17 G18 Sir Adam Beck 2 Refurbishment:

a. Please provide documentation on the decline in unit reliability.
b. Please provide evidence that the industry standard for refurbishing units is every 25 to 30 years to maintain reliability.

D1-SEC-52
[D1-1-2, Attachment 1, Tab 42] With respect to the BCS for Project #89252 SAB1 (Sir Adam Beck 1) Canal Isolation Preparedness Phase 1:

a. Please explain why the project was deferred from 2020 to June 2024.
b. What was the increased cost due to the deferral?
c. Is there any cost sharing with the Ministry of Transportation? If so, please explain. If not, why not?

D1-SEC-53
[D1-1-2, Attachment 1, Tab 44] With respect to the BCS for Project #89505 Abitibi Canyon Concrete Rehabilitation Zone 7, includes a total cost of $35.6M with an in-service target of April 30, 2026:

a. Please provide an update on the anticipated completion date and total cost for this project.
b. Please explain if there were any savings related to "value engineering strategies to optimize project costs …the use of a mobile batch plant".
c. Please provide further information and BCSs, if available, for the capital expenditures shown in line 35 of D1-1-1 Table 2, and the in-service additions shown on line 35 of D1-1-2 Table 4.

D1-SEC-54
[D1-1-1, Table 2; D1-1-2, Table 4] Please provide a revised version of Table 2 (D-1-1) and Table 4 (D1-1-2), that include the annual internal budgeted capital expenditures and in-service amounts for each year between 2016 and 2026, included in that year's Business Plan, similar to what was provided in EB-2020-0290, Technical Conference Undertaking JT 2.15, Attachment 1.

D1-SEC-55
[D1-1-1, Table 2; D1-1-2, Table 4] Please provide a revised version of Table 2 (D-1-1) and Table 4 (D1-1-2), that include the annual internal budgeted capital expenditures and in-service amounts for each year between 2017 and 2026, included in the Business Plan filed in EB-2016-0152 and EB-2020-0290, similar to what was provided in EB-2020-0290, Technical Conference Undertaking JT 2.15, Attachment 2.

D2-SEC-56
[D2-1-1, p.4-5] The evidence discusses an "OPG-defined Value Framework" which "quantifies the value of each investment based on the summation of all benefits and costs in the risk areas. This model is used to help select the preferred projects that provide the highest net benefit to address business needs."

a. Please provide a copy of any internal document or guide that outlines the OPG Value Framework and how each risk/benefit is considered and scored.
b. Does OPG use a software program to prioritize and calculate investments based on net benefits? If so, please provide details.
c. For each nuclear investment/project that is considered as part of the OPG Value Framework,

please provide, a) the project name, b) project number c) each individual benefit/risk score, d) cost, e) net benefit score, f) if the project investment is capital or OM&A, g) if the investment/project was ultimately included in the 2027-2031 plan, h) in-service year(s), and i) any other material outputs of the OPG Value Framework.

D2-SEC-57
[D2-1-1, p.5] The evidence states that: "These investments are prioritized within funding, resource, environmental and scheduling constraints to maximize overall portfolio value based on the Value Framework, taking into account station operation and safety risks." For the purpose of the process used to determine the 2027 to 2031 nuclear budgets, what were the funding and resource constraints used as part of the prioritization process, and how was each determined?

D2-SEC-58
[D2-1-1, Table 2] Please provide a revised version of Table 2 that separates all OPG Nuclear Operations Capital into Darlington, Pickering, and Operations and Project Support.

D2-SEC-59
[D2-1-2, Table 4,a),b); D2-1-3, Tables 4a, 4b] Please provide a revised version of Tables 4a and 4b, that include the annual internal budgeted capital expenditures and in-service amounts for each year between 2022 and 2026, included in that year's Business Plan, similar to what was provided in EB-2020-0290, Technical Conference Undertaking JT 2.15, Attachment 1.

D2-SEC-60
[D2-1-2, Table 4,a),b); D2-1-3, Tables 4a,b] Please provide a revised version of Tables 4a and 4b, that include the annual internal budgeted capital expenditures and in-service amounts for each year between 2022 and 2026, included in the first Business Plan prepared after the approval of the EB-2020-0290 Settlement Proposal, similar to what was provided in EB-2020-0290, Technical Conference Undertaking JT 2.15, Attachment 2.

D2-SEC-61
[D2-1-3, Tables 5a, b, and c] With respect to unallocated project budget:

a. Please explain how the unallocated budget was determined and how the OEB can assess the reasonableness of those amounts where no supporting information, besides the project name, has been provided regarding the potential expenditures.
b. For all projects >$30M, please provide a detailed description, justification for the project, and the preliminary cost estimate.
c. For all unallocated projects between >$10M and <$30M, please provide a detailed description, justification for the project, and the preliminary cost estimate.

D2-SEC-62
[D2-2-1, p.10] Please provide a revised version of Chart 1 that compares actual duration to Release Quality Estimate ("RQE") working, as opposed to high confidence schedule.

D2-SEC-63
[D2-2-1, p.11] Please reconcile the forecast $12.7Bn final budget ($100M below budget) with the Government's February 2, 2026 news release that the project is $150M below budget.

D2-SEC-64
[D2-2-2, p.12-13] Please provide a copy of all DRP Refurbishment Review Board reports and any other oversight report that has not already been filed in previous proceedings.

D2-SEC-65
[D2-2-2] What are the latest earned value metric results for the DRP?

D2-SEC-66
[D2-3-2, p.3] Did OPG undertake any review or assessment of the contracting strategies and/or contract implementation of the DRP? If so, please provide details and if they had been included in the contracts for the Pickering Refurbishment Program ("PRP").

D2-SEC-67
[D2-3-2, Attachment 1, p.18] Please provide the individual Project Management Plans.

D2-SEC-68
[D2-3-3, p.4, Chart 2] For each of the work bundle contract and pricing models, please explain how they differ, if at all, from what was negotiated as part of the DRP.

D2-SEC-69
[D2-3-3, p.4, Chart 2] For Facilities and Infrastructure Projects, OPG says that it had multiple approaches to the pricing models for EPC contracts. Please provide details.

D2-SEC-70
[D2-3-3, p.5] The evidence states that "Atkins was selected for the Pickering RFBR given Atkins is owner of the original design and has significant experience with CANDU refurbishment projects including DRP". Was there any competitive bid process for any aspect of the RFBR that selected Atkins/Aecon JV? If so, please provide details, including information on the process, selection criteria, and number of bidders.

D2-SEC-71
[D2-3-3] Please explain why OPG did not propose an Integrated Contract Model for the PRP.

D2-SEC-72
[D2-3-3, p.9] Please provide a detailed comparison between contract and pricing mechanisms between the PRP and DRP RFR bundles, and provide the rationale for the differences.

D2-SEC-73
[D2-3-3, p.9; EB-2016-0152, D2-2-3, p.12-14 and L-4.3-SEC-015] Using the same format as provided in Exhibit D2-2-3, p.12-14 (EB-2016-0152), please provide charts showing the following scenarios for the RFR Target Pricing:

a. Contractor 10% cost savings
b. Contractor 1% cost savings
c. Contractor 1% overrun
d. Contractor 10% cost overrun
e. Contractor 25% cost overrun
f. Contractor 50% cost overrun
g. Contractor 75% cost overrun
h. Contractor 100% cost overrun

D2-SEC-74
[D2-3-3] During the negotiations or the design of the contract structure and pricing methodology, did OPG undertake any modelling of option and potential outcomes? If so, please provide copies of any analysis undertaken.

D2-SEC-75
[D2-3-3, p.15-17] With respect to the DWI RFP process:

a. Please provide a summary of the 4 bids, including costs, and explain why DIG GP was ultimately selected.
b. Please provide a copy of the memo or similar document OPG prepared for the purpose of approval of the selection of DIG GP.
c. Please provide the target price, Definition Phase fixed price, and neutral band.
d. Please provide a number of scenarios showing the impact of various contractor cost overruns and cost savings.

D2-SEC-76
[D2-3-3, p.17-21] For each Balance of Plant and Facilities & Infrastructure project, does each ESMSA contractor bid on the project? If not, please explain the selection process.

D2-SEC-77
[D2-3-3, p. 21] The evidence states that "Certain scope that includes new infrastructure such as the Common Services Building, Pickering Maintenance Facility, and Security Port Upgrades will be completed via a sole source justification to Makhos Bird Joint Venture ("MBJV")." Please explain why these projects are selected via sole source and how that is appropriate.

D2-SEC-78
[H1-1-1, p.26] The evidence is that the OPG has previously undertaken a feasibility assessment for the refurbishment of the Pickering Units 5-8.

a. Please provide a copy of the previous feasibility assessment.
b. Please provide an explanation of the material difference in the finding of the previous feasibility assessment and the one undertaken that led the decision to undertake the refurbishment.

D2-SEC-79
[D2-3-4, p.2] Please provide a copy of each of the listed primary outputs of the Feasibility Phase.

D2-SEC-80
[D2-3-4, p.3] With respect to the Initiation Phase, please provide:

a. Class 4 cost and schedule estimates
b. Economic feasibility assessment
c. Recommendation to proceed to Definition Phase
d. Materials provided to the OPG Board of Directors approving the completion of the Initiation Phase and transition to the Definition Phase.

D2-SEC-81
[D2-3-4, p.13] The evidence states that: "OPG achieved 36% of engineering for all major scopes in alignment to the recommended practice prior to the establishment of the PRP Release Quality Estimate." What percentage of engineering deliverables has been completed for each of the major

work bundles?

D2-SEC-82
[D2-3-6, p.6] Please provide the referenced probabilistic analysis OPG undertook to determine the PRP schedule.

D2-SEC-83
[D2-3-6, p.7] As part of the DRP each of the Darlington units were returned to service early. Please explain how the proposed PRP schedule accounts for what occurred with the DRP schedule.

D2-SEC-84
[D2-3-7] With respect to the contingency amounts included in the budget:

a. [p.5] Please provide a copy of the PRP Monte Carlo analysis.
b. Please explain any methodological differences between the determination of the PRP and DRP contingency amounts.
c. [p.7] The evidence states that "Allocation of the total contingency across the four units was based on 'risk exposure windows', which refers to the anticipated timing for when the risks or uncertainties would be realized and associated contingency costs would be incurred." Please provide further analysis regarding the risk exposure windows and how specifically that resulted in 41% of the total contingency allocated to Unit 5.
d. What would be the required contingency amount at confidence level of 50%, 75%, 80%, 85%, 90%, 95% and 99%?

D2-SEC-85
[D2-3-8, p.9] OPG is seeking approval for concurrent cost recovery ("CCR") interest amounts over the rate term regarding Units 6-8. If the OEB ultimately determines in a future proceeding, that in whole or in part, the costs of Unit 6-8 are imprudent, what happens regarding the CCR interest paid on those expenditures?

D2-SEC-86
[D2-3-8, p.11-16] For Charts 6-11, please provide a summary breakdown of each work bundle in the RQE budget. For each, please provide a significantly more detailed budget.

D2-SEC-87
[D2-3-8, p.18-20] Please provide individual business cases for each of the early in-service facilities and infrastructure projects.

D2-SEC-88
[D2-3-8; EB-2016-0152, JT 1.17C] Please provide the expected quarterly cumulative capital costs based on the RQE budget for each quarter through the end of the PRP, similar to what was provided in Undertaking JT 1.17C (EB-2016-0152).

D2-SEC-89
[D2-3-8] With respect to the business cases and budgets:

a. Please provide a table that shows every cost estimate (e.g. internal, class, release, and phase) developed for the project, broken down by bundles/category. For each estimate, please provide the date, phase, and reason for the change.
b. Please provide a copy of each business case (for each class and release) developed for the PRP.

D2-SEC-90

[D2-3-8, Attachment 1] With respect to the PRP RQE Memorandum to the OPG Board of Directors:

a. [p.2] The memo states that as part of the definition phase, it included "[r]ecommendations to optimise scope and lower first-of-a-kind ["FOAK"] project risks for Unit 5 have been approved and included in the estimate." Please provide details regarding the recommendations and the impact on optimizing scope and lowering FOAK project risk.
b. [p.4,14] OPG states "[t]he Levelized Cost of Energy (LCOE) is $169/MWh ($2024)". Please provide all underlying calculations and assumptions used in the calculation.
c. [p.5] Please provide a similar memorandum for the Board of Directors for Release 1A-1 and 1A-2.
d. [p.5] The memo states that "checkpoints will be used to confirm that the program cost and schedule estimates remain within the bounding cost and schedule durations requested during the RQE or identify significant changes that may require additional actions to be taken." Please provide details regarding each of the checkpoints.

D2-SEC-91
[D2-3-8, Attachment 2] With respect to the KPMG, *Pickering Refurbishment Project Release Quality Estimate Independent Review*:

a. Which KPMG employees authored the review, and what are their qualifications?
b. [p.6] Please provide the RQE roadmap.
c. Did OPG implement the recommendations as part of the RQE? If so, please provide details regarding each recommendation.

D2-SEC-92
[D2-3-9] For each year of the rate term, how many OPG FTEs will work on the PRP? Please provide a breakdown by each work bundle, and project management/support function.

D2-SEC-93
[D2-3-9, p.7] With respect to cost and schedule performance, please provide the most recent PRP, a) Schedule Performance Index (SPI), b) Cost Performance Index (CPI), c) Cost Variance (CV) and Schedule Variance (SV), d) Estimate at Completion (EAC), and e) Variance at Completion (VAC) scores/values, as well as the inputs (e.g. for CPI, the Earned Value and Actual Cost).

D2-SEC-94
[D2-3-9, p.13] With respect to the Refurbishment Review Board (RRB):

a. Please provide all reports (either formal or informal) produced by the RRB to-date.
b. Please provide the RRB terms of reference, and all other governing documents, including any contracts, retainer agreements or other agreements.
c. Please provide a list of RRB members and their biographies.

D2-SEC-95
[D2-3-9, p.13-14] With respect to PRP Oversight and External Assurance:

a. Please detail the regular reporting that is provided to the Chief Projects Officer, and the OPG Executive Leadership Team regarding the PRP. For each regular reporting mechanism (weekly, monthly, and annual reporting), please provide the latest copy.
b. Please provide all reports to date provided by OPG management, and the Nuclear Oversight function, with the Major Projects Committee of OPG's Board of Directors related to the PRP regarding PRP progress, and any issues that have arisen to date.

D2-SEC-96

[D2-3-9, p.13; D2-4-9, p.16-17] With respect to the PRP and DNNP Oversight, SEC would like to understand how the current and proposed third-party oversight mechanisms for these projects are similar or different for those in place for the DRP.

a. Please provide a copy of the terms of reference, and all other governing documents, including any contracts, retainer agreements or other agreements, between OPG and Burns McDonnell/Modus Strategic Solutions regarding their engagement on behalf of the OPG's Board of Directors regarding oversight of the definition and execution phase of DRP Unit 2, and execution estimate of Unit 3.
b. Please explain the basis for any material differences in the scope of the engagement, including but not limited to reporting, access to OPG Staff and information, independence, and independent support staff, as set out in part(a) compared to the PRP Refurbishment Review Board and the DNNP Small Modular Reactor Review Board.

D2-SEC-97

[D2-4-1, p.5] With respect to the selection of BWRX-300 as the specific technology:

a. Please provide a detailed explanation of the technology selection process.
b. Please provide all materials provided to the OPG Board of Directors regarding the selection of the BWRX-300 as the specific technology.
c. Please provide a copy of any internal document that was created that provides a summary of the outcome of the selection process, a review of the other potential technologies that were considered, and a recommendation for the selection of the BWRX-300.
d. Did OPG undertake any third-party reviews of the selection process? If so, please provide a copy of their report (or similar documents).
e. Please confirm that OPG is the first company to construct a BWRX-300 reactor.
f. As part of the selection process, did OPG (or related entities) receive any preferential benefits with GE-Hitachi regarding preferential benefits to OPG for being the first company to construct a BWRX-300 reactor? If so, please provide details.

D2-SEC-98

[D2-4-1, p.6] The evidence states with the technology selection process complete, OPG's Board of Directors approved the move to the Initiation Phase which included execution of initial commercial agreements.

a. Please provide a copy of the materials provided to the OPG Board of Directors for their decision to move to the Initiation Phase.
b. Please provide details regarding the initial commercial agreements.
c. Did OPG develop any cost estimate for the project at the Initiation Phase? If so, please provide a copy.

D2-SEC-99

[D2-4-1, p.6] The evidence states "[i]n December 2022, OPG's Board of Directors gave approval for the project to proceed to the Definition Phase."

a. Please provide a copy of the materials provided to the OPG Board of Directors for their decision to move to the Definition Phase.
b. Did OPG develop any cost estimate for the project at the Definition Phase? If so, please provide a copy.

D2-SEC-100
[D2-4-1, p.8] OPG is seeking approval of $113.5M of CCR interest amounts over the rate term regarding Units 2-4. If the OEB ultimately determines in a future proceeding, that in whole or in part, the costs of Unit 2-4 are imprudent, what happens regarding the CCR interest paid on those expenditures?

D2-SEC-101
[D2-4-1] With respect to the business cases and budgets:

a. Please provide a table that shows every cost estimate (e.g. internal, class, release, and phase) developed for the project, broken down by category. For each estimate, please provide the date, phase, reason for the change.
b. Please provide a copy of each business case (for each class and release) developed for the DNNP.

D2-SEC-102
[D2-4-2, p.6-8] OPG is using the IPD model for the DNNP.

a. Please provide all materials provided to OPG's Board of Directors and Senior Management where approval of the IPD was sought.
b. Please detail all potential risks and downsides of the IPD model and how OPG has mitigated each.

D2-SEC-103
[D2-4-2, p.13-14] How many OPG FTEs have or will work on the DNNP each year between 2024 and 2031? Please provide a breakdown of those FTEs into the various work bundles and functional teams.

D2-SEC-104
[D2-4-2, Attachment 1 and 2] With respect to the Opinions of Howard Ashcraft:

a. [Attachment 1, p.5] Please provide a copy of the referenced Ashcraft 2022 paper.
b. [Attachment 2, p.2] Please provide a copy of the "redline prepared by Torys to highlight where the Amendment affected or developed provisions in the existing IPD agreement."

D2-SEC-105
[D2-4-2] Please provide a summary of key terms of the IPD agreement similar to that provided for the various key PRP contracts (i.e. D2-3-1, Attachment 1).

D2-SEC-106
[D2-4-2, Attachment 3, p.30] As part of the Project Charter, OPG states as a risk "The Ontario Energy Board (OEB) may not approve full cost recovery through the rate case if the economics exceed existing generation options or if the project exceeds the approved budget." Please provide all analyses undertaken regarding the economics of the project in comparison to existing or other generation options.

D2-SEC-107
[D2-4-3, p.2-3; D2-4-4, p.3] With respect to the Technology Collaboration Agreement:

a. Please provide greater details regarding the agreement contracts, including among other matters, how much OPG contributed versus other contributors.
b. OPG states that the "The TCA also allowed OPG to share the costs associated with developing the first-of-a-kind Standard Plant Design with the Designer and other parties

interested in constructing a SMR after OPG." Why would the vendor, not OPG, be responsible for the costs associated with the development of a standard plant design?

c. Who owns the intellectual property regarding the standard plant design and, is or will, OPG be compensated for other entities who construct a BWRX-300 reactor based on that design?

D2-SEC-108
Please provide a table that shows the major difference between the contracting structure between the DRP, PRP, and DNNP, and explain why each is best suited for each project, and the risks and the benefits of each as compared to the others used.

D2-SEC-109
[D2-4-3, Attachment 1] For each scenario, please provide the total cost and the total cost paid by OPG.

D2-SEC-110
[D2-4-4, p.8-9] Please provide a more detailed review of the lessons learned from other large projects, and specifically the DRP and other recent large nuclear new build mega projects (e.g. Vogtle). Please provide any reports or analysis undertaken regarding those projects, and lessons learned.

D2-SEC-111
[D2-4-7] With respect to the development of the contingency amount:

a. Please explain how the development of the contingency amount differs from what was included in the DRP and proposed to be included in the PRP.
b. [p.4-7] Please provide the document results of the Monte Carlo simulation.
c. [p.8] Please explain why the total Unit 1 contingency amounts included in Chart 1 differ from that included in the RQE Budget (D2-4-8, p.8, Chart 2).
d. [p.9] The evidence states: "Recognizing the FOAK nature of the technology, higher uncertainty, and limited relevant historical data to inform the risk profiles, OPG has allocated $193M to the contingency pool."
    i. Please explain how OPG determined the specific amount of incremental Non-IPA contingency, which should be included in the budget ($59M = $193M – $134M).
    ii. Does the Monte Carlo simulation not include risks related to each of the FOAK nature of the technology, higher uncertainty, and limited relevant historical data to inform the risk profile?
    iii. Including the incremental $59M of contingency, what is the total confidence level calculated at?

D2-SEC-112
[D2-4-8, p.10-18] Charts 3-10 provide a summary breakdown of each work bundle/scope in the RQE budget. For each, please provide a significantly more detailed budget.

D2-SEC-113
[D2-4-8, Attachment 2] With respect to the BTTC *Third Party Assurance Report*:

a. [p.11] The Report finds certain sub-areas with a maturity level of 2, which is below a level 3 (Effective). Has OPG brought those sub-areas to at least a level 3, and if so, were the changes incorporated into the RQE budget?
b. [p.12] The Report finds partial compliance with 4 sub-areas of the Estimate Plan. Has OPG brought those sub-areas into compliance, and if so, were the changes incorporated into the

RQE budget?

c. [p.13-16] For each of the key recommendations, has OPG implemented the recommendations, and if so, were they incorporated into the RQE budget?

D2-SEC-114
[D2-4-9, p.7-8] With respect to cost and schedule performance, please provide the most recent DNNP, a) Schedule Performance Index (SPI), b) Cost Performance Index (CPI), c) Cost Variance (CV) and Schedule Variance (SV), d) Estimate at Completion (EAC), and e) Variance at Completion (VAC) scores/values, as well as the inputs (e.g. for CPI, the Earned Value and Actual Cost).

D2-SEC-115
[D2-4-9, p.16] With respect to DNNP Oversight and Assurance Model:

a. Please detail the regular reporting that is provided to the Chief Projects Officer, and the OPG Executive Leadership Team regarding the DNNP. For each regular reporting mechanism (weekly, monthly, and annual reporting), please provide the latest copy.
b. Please provide all reports to date provided by OPG management, and the Nuclear Oversight function, with the Major Projects Committee of OPG's Board of Directors related to the DNNP regarding DNNP progress, and any issues that have arisen to date.
c. With respect to the DNNP Board of Directors,
    i. Has the DNNP Board of Directors been established yet? If so, please provide details of the membership.
    ii. Please provide all materials provided to the DNNP Board of Directors to date.

D2-SEC-116
[D2-4-9, p.17] With respect to the Small Modular Reactor Review Board (SMRRB):

a. Please provide all reports (either formal or informal) produced by the SMRRB to-date.
b. Please provide the SMRRB terms of reference, and all other governing documents, including any contract, retainer agreements, or other agreements.
c. Please provide a list of SMRRB members and their biographies.

D2-SEC-117
[D2-4-10, Attach 1] With respect to the Testimony of Joseph Miller (Pegasus-Global) in respect to the DNNP:

a. [p.30] Please provide a copy of the document referenced at ft 36 "Summary of DNNP Integrated Project Agreement (17 Oct 2025)".
b. [p.32] Pegasus-Global says that "OPG has used certain elements of an IPD model in the DRP as well as the Otto Holden Generating Station refurbishment". Please provide details regarding the use of the IPD model in those projects.
c. [p.69] Please provide copies of the most recent DNNP generated reports listed.
d. [p.78] Please provide a copy of the evidence filed by Pegasus-Global in the Vogtle 3 & 4 Prudence Review and Rate Adjustment application.

D3-SEC-118
[D3-1-1, p.9] Please explain why the DNNP requires its own EAM system, and why it cannot use the OPG EAM system.

D3-SEC-119
[D3-1-1, p.12] The evidence states: "OPG is planning a phased transition to a modern ERP solution that will support Supply Chain and RG operations in 2029, followed by Nuclear operations in 2031.

The specific technology platform has not yet been selected." If the technology platform has not been selected, please explain how OPG determined the budget for the new supply chain ERP that is used in the Application.

D3-SEC-120
[D3-1-1] With respect to cloud computing:

a. Please provide a table that shows all Support Service capital expenditures and Corporate Service OM&A costs for each year between 2020 and 2031.
b. Please provide a table that shows all cloud computing costs for each year between 2020 and 2031, broken down into capital and OM&A.
c. For all cloud computing costs included in capital, please provide the specific internal guidance interpreting both US GAAP and OEB policy regarding cloud computing capitalization.

D3-SEC-121
[D3-1-2, Table 2e] With respect to the Renewable Generation Training Centre with an in-service date of December 2027, is the full cost used in calculating the ASF for Regulated Hydroelectric in F3-2-1 Table 1? Please provide the full calculation.

D3-SEC-122
[D3-1-1, Attachment 1] With respect to the Enterprise Digital Roadmap:

a. Is the single page document the entire 'roadmap' or strategy, or is there a broader document? If such a document exists, please provide a copy.
b. Please provide details of, a) each of the specific projects/program/systems, b) a description, and c) the costs (capital expenditure, in-service addition, and OM&A) for each year between 2020 and 2031.

D3-SEC-123
[D3-1-2, Attachment 1, Tab 6] With respect to the Corporate Headquarters Renovation project:

a. Please provide a copy of the full business case (or similar document) regarding the initial decision to forgo constructing a new facility and purchase the property at 1908 Colonel Sam Drive.
b. [p.2] Please provide a full copy, with all formulas intact, of the referenced financial modeling.
c. [p.5] Please provide a copy of the referenced 2022 assessment.
d. Please provide a detailed breakdown of renovation requirements. Please explain how they were determined and what alternatives were considered.
e. Please provide a detailed breakdown of the renovation costs.

D3-SEC-124
[D3-1-2, Table 2c] Please provide further details, including the business case summary, of the Data Center Migration project.

D3-SEC-125
[D3-1-1, Table 2; D3-1-2, Table 5a] Please provide a revised version of the referenced tables that include the annual internal budgeted capital expenditures and in-service amounts for each year between 2022 and 2026, included in that year's Business Plan, similar to what was provided in EB-2020-0290, Technical Conference Undertaking JT 2.15, Attachment 1.

D3-SEC-126
[D3-1-1, Table 2; D3-1-2, Table 4a, 4b] Please provide a revised version of the referenced tables that include the annual internal budgeted capital expenditures and in-service amounts for each year between 2022 and 2026, included in the first Business Plan prepared after the approval of the EB-2020-0290 Settlement Proposal, similar to what was provided in EB-2020-0290, Technical Conference Undertaking JT 2.15, Attachment 2.

D3-SEC-127
[D3-1-2, Table 5a] Please provide a revised version of Table 5a, that includes a column for the 2020 and 2021 in-service additions that were used to calculate the OEB approved opening rate in EB-2020-0290.

E1-SEC-128
[E1-1-1, p.6] Please provide a list of the current planned outages for hydroelectric stations over 2027-2031, including start date and expected outage length.

E1-SEC-129
[Auditor General of Ontario, 2022 Report, Value-for-Money Audit: Ontario Power Generation: Management and Maintenance of Hydroelectric Generating Stations; Auditor General of Ontario, 2024 Annual Report, Follow-up: Management and Maintenance of Hydroelectric Generating Stations]

In its 2022 Annual Report, the Auditor General made the following recommendation:

> "To protect the interests of Ontario ratepayers, we recommend that Ontario Power Generation collaborate with the Independent Electricity System Operator and the Ontario Energy Board to assess options for more cost-effective ways to be compensated for surplus baseload generation conditions, such as covering only fixed costs when hydroelectric generating stations are requested to spill water in order to curtail production."

In its 2024 Annual Report, the Auditor General Report wrote regarding the lack of implementation of the recommendation in its 2022 Report:

> "While OPG anticipates that the OEB will review the methodology for calculating the Hydroelectric Surplus Baseload Generation Variance Account, this review will not include an assessment that will address this recommended action. This is because the methodology review is intended to assess options to reduce amounts recorded in this Hydroelectric Surplus Baseload Generation Variance Account instead of options to adjust the compensation methodology."

a. Has OPG undertaken any analysis regarding where there are <u>more</u> cost-effective ways to compensate it with respect to SBG? If so, please provide. If not, please explain why not.
b. Please explain why OPG has not collaborated with the IESO to date regarding an appropriate compensation mechanism for forgone electricity production due to SBG conditions.
c. What methodological review is OPG referring to in the 2024 follow-up review and why does it believe that it does not include compensation methodology?

E1-SEC-130
[E1-2-1, p.8, 9, 13, 15] Please update Charts 2-5 to include the latest month available.

E1-SEC-131
[E1-2-1] With respect to the proposed changes to Hydroelectric Incentive Mechanism ("HIM") revenue sharing methodology:

a. [p.13] As it related to HIM payments in Market Renewal, "OPG has taken a measured approach in interpreting these results alongside its longer-term modelled expectations of market operations", and that "[a]s the IESO noted in its update on Renewed Market performance and operations: the ability to draw conclusions at this point is still limited". On that basis, please explain why it is appropriate to change the HIM revenue sharing methodology now.
b. [p.17-18; EB-2023-0336, H-SEC-04c] Please reconcile OPG's proposed changes to the HIM with its statement that in EB-2023-0336 that "HIM revenue sharing is not considered in the economic decision making for PGS operations".

E1-SEC-132
[E1-2-1, p.16] Please provide all underlying calculations included in Chart 6. For the calculation of the Payments for Non-OPG Supplier Generation, please provide a detailed explanation of the methodology, all assumptions made, and provide any underlying model with all formulas intact, or if applicable, underlying source code and data files.

E1-SEC-133
[E1-2-1, p.17] The evidence states "As a result, Ontario Zonal Prices are projected to rise, increasing the value of incremental time-shifted hydro production and the customer benefit in 2027." Please provide OPG's forecast Ontario Zonal Price through the end of 2027.

E1-SEC-134
[E1-2-1, Attachment 1, p.8] Please explain how OPG forecasts the amount of SBG. Please provide all underlying calculations, including all assumptions made, and provide any underlying model with all formulas intact, or if applicable, underlying source code and data files.

E1-SEC-135
[E1-2-1, Attachment 1, p.22] Please provide an analysis, all underlying calculations, including all assumptions made, and provide any underlying model with all formulas intact, or if applicable, underlying source code and data files, of how much more often the PGS would have, or will be, cycled, if OPG's proposed changes to the HIM revenue sharing mechanism had been/will be implemented.

E1-SEC-136
[E1-2-1, Attachment 1, p.22; Decision and Order (EB-2013-0321), November 20, 2024, p. 12-13)] Please explain what has changed since the OEB's Decision in EB-2013-0321 regarding the HIM, and the structure of the revenue sharing that warrant the OEB to make the changes OPG has proposed.

E2-SEC-137
[E2; EB-2020-0290, E2-01-CCC-43] Please expand E2-01-CCC-43 Attachment 1 and Attachment 2 (EB-2020-0290) to include 2021-2026 approved and actual/budgets, as well as 2027-2031 forecast amounts.

E2-SEC-138
[E2-1] Please provide the production forecast (TWh) for each year between 2021 and 2031 (actual/budget and forecast) by nuclear unit.

E2-SEC-139
[E2-1] Please provide a copy of the annual internal nuclear production forecast for each year between 2022 and 2026.

E2-SEC-140
[EB-2020-0290, E2-01-Staff-190] The evidence in EB-2020-0290 was that OPG planned to investigate the use of technology that would allow OPG to reduce the duration of a planned 2022 Pickering VBO.

a. Please provide a result of the investigation and if the new technology was implemented. If it was implemented, please provide details of the results.
b. Is the same technology applicable to the planned Darlington VBO, and if so, has it been included in the forecast length of the outage?

E2-SEC-141
[EB-2020-0290, L-E2-01-OAPPA-002, Attachment 1] With respect to EB-2020-0290, L-E2-01-OAPPA-002, Attachment 1:

a. Please provide a revised version of the table that includes the actual/revised budgeted outage duration (days) for each planned outage.
b. Please provide a revised version of the table for all planned outages between 2027 and 2031.

E2-SEC-142
[E2-1-1] Please update Charts 2-4 to include 2025 actuals.

E2-SEC-143
[E2-1-2, p.4-7] Based on the explanation of variances between actuals/budget and approved, please confirm the impact between 2022 and 2026 on the actual/budget production forecast compared to approved as a result of the DRP being ahead of schedule is 10.4 TWh (2022: 0, 2023: +2.3, 2024: +0.7, 2025: +3.5, 2026: +3.9). If not confirmed, please provide the correct amount by year.

E2-SEC-144
[E2-1-2] Please provide a table that shows all planned 2027-2031 outages that were included in EB-2020-0290 for 2022-2026 production forecast that have been deferred into the 2027-2031 period. For each, please explain the reason for the deferred outage, provide the forecast length of time (days) and production impact (TWh) in EB-2020-0290, and the revised forecast length of time (days) and production impact (TWh).

E2-SEC-145
[E2-1-2, p.11] Please provide further details regarding the DNNP 2031 warranty outage. Please provide the length of time (days) and production impact (TWh).

F1-SEC-146
[F1-1-1, p.4-5] With respect to refurbishment program/projects:

a. With respect to the turbine-generator refurbishment program, please provide a list of projects that constitute the $2,193.6M of capital expenditures on refurbishment projects in the 2027-2031 forecast period.
b. Please provide a list of the 53 regulated hydroelectric refurbishment projects that are expected to come into service during the 2027-2031 forecast period, including the total cost.

F1-SEC-147
[F1-1-1, p.6] Please provide further details on the Renewable Generation Programmatic

Collaboration Agreement ("RG PCA"), including but not limited to commitments that OPG has made to the Original Equipment Manufacturers ("OEM") in terms of amount of work, any premiums or penalties, etc.

F1-SEC-148
[F1-1-1, p.6] For each of the RG PCA Agreements:

a. Please describe the process that was used to arrive at the agreement.
b. Please provide copies of the agreements.

F1-SEC-149
[F1-1-1, p.11-12] Please provide a breakdown, by year and by component, of the $5.7M of incremental costs necessary to comply with the 2019 amendments to the Fisheries Act.

F1-SEC-150
[F1-1-1, p.15-16] Please provide a copy of the OPG/Hydro-Québec O&M Agreement and the RG Excellence Plan.

F1-SEC-151
[F1-1-1, p.16-17] For each continuous improvement initiative for the hydroelectric business, please provide for each year between 2025 and 2031, a) the annual costs, and b) any quantified benefit (in cost savings or increased output). Please provide all calculations including any details regarding methodology and assumptions made.

F1-SEC-152
[F1-1-1, p.16-17] For each historic or current continuous improvement or productivity initiative for the hydroelectric business, please provide for each year between 2016 and 2024, a) the annual costs, and b) any quantified benefit (in cost savings or increased output). Please provide all calculations including any details regarding methodology and assumptions made.

F1-SEC-153
[F1-1-1, p.17-36] With respect to hydroelectric key performance metrics:

a. Please update Charts 1,3,4,6,8,10 and 12 with actuals for 2025.
b. [p.25, Chart 8] Please explain the high Equivalent Forced Outage Rate of 14% for Pine Portage GS as shown in 2024.
c. [p.29] Please provide the targets for Regulated Hydroelectric Total Generation Cost ("TGC") Performance for 2025-2031. If targets are not developed, please explain why.
d. [p.29] Please explain why redevelopment projects are excluded from TGC.

F1-SEC-154
[F1-2-1, Tables 1 and 2] With respect to Hydroelectric Base OM&A:

a. Please provide a breakout of the total FTEs (shown in F1-1-1 Table 2b) by the categories listed in F1-2-1 Table 1.
b. Please provide details on how overtime costs shown in F1-2-1 Table 2 are forecasted.
c. Please provide a further breakdown of Other Purchased Services costs shown in F1-2-1 Table 2.

F1-SEC-155
[F1-2-2, p.1] Please explain the derivation of the materiality threshold used to explain variances for the Hydroelectric OM&A (i.e. "10% or greater at the function level, subject to a minimum

materiality limit of $1M”).

F1-SEC-156
[F1-3-1, p.3] With respect to hydroelectric portfolio projects:

a. Please provide a listing, by year, of turbine-generator overhaul projects by station completed or forecasted to be completed between 2022 and 2026 and associated costs.
b. Please provide a listing, by year, of concrete restoration initiatives by station completed or forecasted to be completed between 2022 and 2027 and associated costs.

F2-SEC-157
[F2-1-1; EB-2020-0290, F2-Staff-196] With respect to OPG’s nuclear benchmarking performance:

a. Please provide a table that compares OPG’s actual performance between 2021-2025, against its annual targets provided in EB-2020-0290, F2-Staff-196, Charts 3 and 4. Please ensure the same methodology used for the targets is used for actual performance.
b. Please provide a comparison of OPG’s actual performance between 2021-2025, against the annual targets for Normalized Total Generation Cost Per MWh and Normalized Total Generation Cost Per Unit provided in EB-2020-0290, F2-Staff-196, Charts 3 and 4. In doing so please, a) use the same methodology for the targets that is used for actual performance, b) revise the annual targets to reflect the actual in-service dates as a result of the DRP, as compared to what was forecast when setting the targets, c) revise the annual targets to reflect Pickering extended operations and extension timing, compared to what was forecast when setting the targets. For each of (b) and (c) please explain the specific calculations made and their basis.
c. For each of OPG’s Value For Money metric scores, please provide all underlying calculations of the scores, and provide direct reference to amounts included in the cost and production tables in its pre-filed evidence for those numbers. If adjustments were made from information included in the various cost and production forecast included in the evidence, please provide a full explanation.

F2-SEC-158
[F2-1-1, p.19-25, Chart 3 and 4] Please provide a revised version of Charts 3 and 4 using the existing 2018 benchmarking methodology (as applied in EB-2020-0290).

F2-SEC-159
[F2-1-1] Please provide a copy of the 2025 Benchmarking Report. If it is not available, please provide OPG’s benchmarking results.

F2-SEC-160
[F2-1-1, p.27-32] For each of the current fleet-wide improvement initiatives for the nuclear business, please provide for each year between 2025 and 2031, a) the annual costs, and b) any quantified benefit (in cost savings or increased output). Please provide all calculations including any details regarding methodology and assumptions made.

F2-SEC-161
[F2-1-1, Attachment 1] For each of the fleet-wide initiatives identified in EB-2020-0290 implemented for the nuclear business, please provide for each year between 2021 and 2031, (a) the annual costs, (b) any quantified benefit (in cost savings or increased output). Please provide all calculations including any details regarding methodology and assumptions made.

F2-SEC-162
[F2-1-1, Attachment 4] With respect to the ScottMadden, *OPG Nuclear Cost Performance Benchmarking* Report*:*

a. [F2-1-1, Attachment 7, p.2] ScottMadden was asked to "[c]conduct a new, holistic study of nuclear cost performance" in part by "determining cost metric normalizations and peer group changes to account for non-controllable factors and <u>facilitate more reasonable benchmark comparisons.</u>"[emphasis added] Please explain how and on what basis did <u>OPG</u> determine that the current methodology required, at the very least, was a "more reasonable" benchmarking comparison.
b. [p.11] Please provide a separate version of the Figure on p.11 for each specific adjustment separately.
c. [p8-9] Please explain why ScottMadden believes that it can find statistically significant impact on cost for CANDU technology when it only makes up 3 of the 57 nuclear sites in its sample.
d. [p.9] Please explain why it is appropriate to consider age from the initial in-service date of the unit as opposed from the date of its full refurbishment.
e. [p.12] Please provide the outage-adjustment working papers used to calculate adjusted MWh for all 57 sites for the years 2006 to 2023. If any special treatment was applied to any plant-year in the outage adjustment (including any adjustments related to refurbishment periods), please identify the plant-years and show exactly how that treatment was implemented in the working papers.
f. [p.12] Please identify the benchmark plant use and provide its planned outage % by year and its 2006 to 2023 average (the value used as the benchmark).
g. Did ScottMadden undertake any analysis of the relationship between the number of units on a site and total generating costs? If, so please provide details.

F2-SEC-163
[EB-2020-0290, JT 1.27, Attachment 1] Please provide a revised version of EB-2020-0290 JT 1.27, Attachment 1, to include 2020-2024 actual data.

F2-SEC-164
[F2-1-1, Attachment 5] With respect to the Indeavor, *OPG Nuclear Staff Benchmarking* Report:

a. [p.6] The Report states "OPG reviewed EUCG (Electric Utility Cost Group) staffing data for 2024, and allocated staffing headcount to corresponding Indeavor functions." Does this mean OPG allocated its employees or that it allocated all EUCG employees to the corresponding Indeavor function? Please explain why OPG, and not Indeavor, was responsible for this task.
b. Please explain <u>all</u> changes to the data collection approach and study methodology used in the previous Goodnight Studies.
c. [p.8] The study excluded the capital staffing function. How many OPG FTEs fall into this category and does the exclusion include all capital-related work and staff involved in any projects set out in Exhibit D2, including support functions?
d. [p.10] The peer group included 4 companies, and 9 sites.
    a. For each site, please provide the number of units, and MWs.
    b. How does this compare to previous staff benchmarking studies included in the last three OPG applications?
e. [p.10] OPG currently operates two sites with more than 2 units per site. Please explain how

Indeavor normalized for the difference in sites per company and units per site.

f. [p.14] Please provide the chart, “Site Headcount – Indeavor Functions”, in a tabular format in Excel.
g. [p.16] Please provide OPG’s views on the drivers of the material variances (both positive and negative) in certain functions compared to the benchmark.
h. [p.17] Please provide a revised version of “Headcount Variance by Function”, reflecting variances as a percentage of the benchmark, as opposed to variance in the headcount number.

F2-SEC-165

[F2-1-1, Attachment 5, p.8] With respect to the Indeavor, *OPG Nuclear Staff Benchmarking* Report, the study excluded Purchased Services, which is a change from previous studies. Indeavor says: “Without the ability to interview benchmark sites and fully analyze PWR contract staffing, the data was excluded from both data sets.”

a. [EB-2020-0290, F2-1-1, Attachment 6, p.11] Using the FTE categories used by Goodnight in previous studies, please explain what is included in the Purchased Services exclusion.
b. Please explain how its ability to interview benchmark sites and analyze PWR contract staffing differs from what Goodnight was able to do in previous studies?
c. On the same basis that it has calculated OPG FTEs in other functions, how many FTEs does OPG have in Purchased Services?

F2-SEC-166

[F2-1-1, Attachment 5] With respect to the Indeavor, *OPG Nuclear Staff Benchmarking* Report:

a. [p.13] What is the total OPG FTE nuclear headcount (including those excluded from the study), including all the categories of FTEs included in the previous Goodnight Study (regular, term, non-regular, augmented, Oncore, contractor, and other purchased services). Please reconcile your answer with the information provided in F2-1-1, Table 2a.
b. [EB-2020-0290, F2-1-1, Attachment 6, p.11] Please provide the OPG FTEs and benchmark FTEs, on a similar basis as provided in EB-2020-0290, F2-1-1, Attachment 6, p.11, which shows the categorizing of OPG FTEs by type (regular, term, non-regular, augmented, Oncore, contractor, etc.). Please also include Purchased Services FTEs on a similar basis, even if they are not included in the Total OPG FTEs.

F2-SEC-167

[F2-2-1, Tables 1a, 1b] Please provide the number of FTEs per function per year.

F2-SEC-168

[F2-3-1] With respect to unallocated project budget:

a. [p.2] Please explain how the unallocated budget was determined and how the OEB can assess the reasonableness of those amounts where no supporting information, besides the project name, has been provided regarding the potential expenditures.
b. [F2-3-3, Table 4] For each project, please provide a detailed description, justification for the project, and the preliminary cost estimate.

F2-SEC-169

[F2-5-1, p.9] The evidence states that: “OPG’s financial coverage limits are determined using a quantitative risk management model that applies efficient frontier analysis to optimize the balance between cost risk and opportunity risk associated with uranium pricing." Please provide details of the quantitative risk management model details and outputs underlying the statement that it balances between cost and opportunity risk, including but not limited to the definition of "cost risk" and "opportunity risk", and what is meant by "optimize the balance".

F2-SEC-170
[F2-5-1, p.11] Please expand Chart 3 to provide the price/pricing methodology for each contract.

F2-SEC-171
[F2-5-1, p.12-13] With respect to the uncontracted uranium requirements:

a. Please provide a copy of the forecast UxC High-Price Midpoint and the Mid-Price Midpoint curve.
b. If OPG had used the UxC Mid-Price Midpoint, what would be the change in forecast fuel costs each year between 2027 and 2031? Please provide all calculations.

F3-SEC-172
[F3-1-1, p. 6-7] The evidence states "[s]ince EB-2020-0290, Support Services have undertaken a number of initiatives that have enabled OPG to partly mitigate the cost impact of the growing internal demand for services and increasing complexity in the external landscape." For each of the implemented initiatives, please quantify the savings. In doing so, please provide the basis of the calculation including all assumptions.

F3-SEC-173
[F3-1-1, Attachment 2] With respect to The Hackett Group, Benchmarking Study:

a. Please detail all methodological changes between the study filed in this application and that filed in EB-2020-0290.
b. [p.8] For each of the peer group companies, please provide the percentage of their revenue that comes from, a) nuclear generation, b) hydroelectric generation, c) other generation, d) transmission and distribution, and e) other.

F3-SEC-174
[F3-1-1, Table 1] Please provide the number of FTEs by corporate cost function.

F3-SEC-175
[F3-1-1] With respect to Corporate & Technology Services:

a. [p.7] Please provide a copy of the analysis OPG used to determine it was better to repatriate 250 NHSS Staff as opposed to renewing its NHSS IT services agreement.
b. [Table 6] Please provide a breakdown of IT Support Costs.

F3-SEC-176
[F3-1-3] Please provide a breakdown of forecast/actual costs related to this application regardless of the year they are incurred by category (expert witness/consultants, external legal counsel, intervenor and OEB costs, and other). Please also provide actual costs incurred by category as of the date of the filing of this application, as well as actuals for the EB-2020-0290 application by category.

F3-SEC-177
[F3-1-1, Tables 1-3c] With respect to Corporate Support & Administrative Groups OM&A Costs, is Table 1 (OPG) the costs of OPG regulated facilities or all OPG costs (regulated and unregulated)? If the latter, please explain why the totals in Table 1 (OPG) are not the sum of Tables 2 (Regulated Hydroelectric), Table 3 (OPG Nuclear Facilities) and Table 3c (DNNP Facilities).

F3-SEC-178
[F3-1-1, F3-1-2] With respect to support services and asset service fees, OPG has only provided the allocated amounts of the total OPG costs for hydroelectric to 2027.

a. [F3-1-1] Please expand Tables 2, 5, and 7b to include amounts allocated to regulated hydroelectric for each year between 2028 and 2031.
b. [F3-1-2] Please expand Table 1b to include amounts allocated to regulated hydroelectric for each year between 2028 and 2031.

F3-SEC-179
[F3-1-4] Please provide a copy of all shared services or similar agreements between OPG's affiliates and OPG.

F3-SEC-180
[F3-1-4, Attachment 1, p.12] Please provide a live copy of the referenced OPG cost allocation model with all formulas intact.

F3-SEC-181
[F3-2-1] With respect to Asset Service Fees ("ASF"):

a. [p.1] The evidence states, "[t]he ASF methodology considers that to the extent that 90% or more of the beneficial use of joint-use asset relates to a particular business, the related assets are fully attributed to that business." Does this mean that an asset is used 91% by the regulated business, and 9% by an unregulated business, therefore the unregulated business bears no cost of the asset? If, so please explain why that is appropriate.
b. [p.3-6] Please provide the underlying calculations used to determine the other costs, depreciation expense and tax-adjusted return for each of the Corporate Headquarters and Corporate IT ASF to each of the regulated segments (nuclear, DNNP, and hydroelectric).

F3-SEC-182
[F3-2-1, Table 1] With respect to Asset Service Fees (ASF):

a. Please provide the number of IT-end users for nuclear, DNNP, and hydroelectric which are used to allocate IT related Support Services costs under OPG's cost allocation methodology.
b. Please explain the increase in Joint-use Renewable Generation Assets allocated to Regulated Hydroelectric in 2023.

F3-SEC-183
[F3-2-1] With respect to the Nuclear Isotopes Asset Usage Fee:

a. Please provide the full underlying calculations, and the basis for the inputs.
b. Does the fee include Laurentis Energy Partners plan to produce Lutetium-177 and Yttrium-90?

F4-SEC-184
[F4-1-1, p.13-14] Please explain why all of these assets that are intended to have service lives "align with the station's post refurbishment life" do not have the same service life.

F4-SEC-185
[F4-1-1, p.17] Please provide a table reconciling the increases in depreciation from 2021 to 2031 to "the impact of in-service additions across the fleet".

F4-SEC-186
[F4-1-1, Attachment 2, p.5] Please explain why the end-of-life ("EOL") dates for Bruce A and Bruce B in the table are not December 31, 2064, as described in the text.

F4-SEC-187
[F4-1-1, Attachment 7] With respect to the Concentric, *Assessment of Regulated Hydroelectric Asset Depreciation Rates* (November 2025) Report:

a. [p.4] Please provide details of the extent, if any, to which the depreciation rates and asset service lives of OPG's regulated hydroelectric assets differ from the depreciation rates and asset service lives of OPG's unregulated hydroelectric assets.
b. [p.8] Please confirm that the information on retirement transactions included full vintage data.
c. [p.10] Please confirm that the "analyses provided to DRC" referred to are on the record in this proceeding, or, if not, provide them.
d. [p.12; Attachment 12 p.14] Given that Concentric has completed depreciation studies on all of the members of the peer group, why is the reliance on "lives in use by peer utilities" throughout the report not circular?
e. [p.17] Please restate Table 1 with original cost and net book value broken out by vintage.

F4-SEC-188
[F4-1-1, Attachment 12, p.16-17] With respect to the Concentric, *Assessment of Regulated Hydroelectric Asset Depreciation Rates* (December 2019) Report, please restate Table 1 to include, for each of the four categories, the gross book value and accumulated depreciation each year.

F4-SEC-189
[F4-3-1, p.21, Figure 4a] Please explain why the percentage of nuclear allocation management – supervisors to total employees has increased as compared to 2020-2023.

F4-SEC-190
[F4-3-1, p.35] Does the contribution ratio set out in Figure 9 reflect the actual or forecast the overall OPG-wide contribution ratio, or does this reflect only a sub-set of employees (e.g. newer employees)?

F4-SEC-191
[F4-3-1] With respect to the Ontario Public Sector Salary Disclosure List:

a. For each of the most recent years available, what percentage of OPG's employees were on the Public Sector Disclosure list?
b. For most recent year available, please provide the total number of OPG employees whose

salaries are at or above, a) $100,000, and b) $200,000.

F4-SEC-192
[F4-3-1] Please provide details of all material changes made to the current collective agreement as compared to those in place at the time of the filing of EB-2020-0290.

F4-SEC-193
[F4-3-1, p.5] The evidence states notes that the current collective agreement with the PWU expires on March 31, 2027, and the Society collective agreement has expired.

a. For the purpose of the budgets included in the Application for 2027-2031, what assumptions has OPG made regarding the Society's collective agreement?
b. Please quantify the impact, if any, between the response to part (a) and what was decided by way of the Arbitration Decision, dated January 26, 2026. Please provide all calculations.
c. For the purpose of the budgets included in the Application for 2027-2031, what assumptions has OPG made regarding the next PWU collective agreement (beginning April 1, 2027)?

F4-SEC-194
[F4-3-1] Please provide a breakdown of the cost impact (additional cost and/or savings) from all changes in the collective agreements with the PWU and the Society since the last application, for each of the following time periods, a) the term of each collective agreement, b) the test period (2027-2031), and c) the total impact if the change extends beyond the test period. Please detail all assumptions made and full calculations. In your response, please provide similar tables included in response to EB-2020-0290, F4-03-SEC-145.

F4-SEC-195
[F4-3-1, p.30] With respect to the Stakeholder Return Program ("SRP"):

a. Please provide the percentage applied to forecast corporate earnings before tax ("EBT") for each year 2016 to 2031. Please note if the percentage is different for nuclear and hydroelectric.
b. Please explain how the percentages for 2026-2031 were determined.

F4-SEC-196
[F4-3-1, Attachment 1, p.3] Please provide a revised version of Appendix 2K, that, a) separates Management into executive and non-executive management, b) breakdown compensation between capital and OM&A, and c) include an additional table that includes all employees for hydroelectric, nuclear, and DNNP.

F4-SEC-197
[F4-3-1, Attachment 3] With respect to the WTW, *Total Compensation Benchmarking Study*:

a. Please detail all methodological changes between the study filed in this application and that filed in EB-2020-0290.
b. Please revise the results of the study so that they provide separate results for each of the general and energy industry.

F4-SEC-198
[F4-3-1, Attachment 3, p.16-17] With respect to the WTW, *Total Compensation Benchmarking*

Study:

a. For each of Management, PWU, and Society, please provide an estimate of the dollar difference between the weighted average total remuneration (including Hydro One Share Grants) for OPG and the P50 median used in the study, and then allocated to each of nuclear, DNNP, and hydroelectric, and to each of capital and OM&A. Please provide the amount for the year the study is representative of and for each year between 2027 and 2031.
b. Please provide a step-by-step explanation of how the estimate was reached, including all supporting calculations so the methodology can be assessed and the calculations verified. In doing so, please also provide a link to what is included in Appendix 2-K (F4-3-1, Attachment 1).
c. Please provide the analysis for both Nuclear Authorized at the 50th and 75th percentile.

F4-SEC-199
[F4-2-1, p.3, 8] OPG proposes that the announced extension of the accelerated investment incentive program ("AIIP") during the bridge year and IR term be captured through variance accounts including the Income & Other Taxes Variance Account. If the impacts were included in the revenue requirement sought for approval, please provide the impact on the income tax expense for each year. Please provide all calculations.

F4-SEC-200
[F4-2-1] Please provide an estimate of the weighted average capital cost allowance ("CCA") rate for each of, a) nuclear operations capital, b) support services capital, and c) regulated hydroelectric capital, each year between 2022 and 2031, excluding the impact of the AIIP.

G1-SEC-201
[G1-1-1, Table 1] With respect to hydroelectric other revenue:

a. Please provide 2025 actuals.
b. Please explain the forecasted drop in Ancillary Services revenue (line 1) in 2026 and 2027 from the 2016-2024 average.

G2-SEC-202
[G2-1-1] With Laurentis Energy Partners ("Laurentis"):

a. Does Laurentis, or its subsidiaries, utilize current or former OPG nuclear employees for the purposes of its various nuclear consulting, project management, and technical services? If so, how does it compensate OPG for the use of these employees?
b. [Laurentis New Nuclear brochure, dated July 18, 2024, p.2] Please explain what Laurentis means when it says that it "leverages decades of nuclear power knowledge through its parent company, Ontario Power Generation (OPG)" and explain how it compensates the OPG regulated business for this knowledge.
c. What revenue from Laurentis is included in OPG's 2027 to 2031 Other Revenue Forecast?

G2-SEC-203
[G2-1-1] With respect to isotope production, how does OPG determine which isotopes produced at Darlington or Pickering will be extracted and sold by OPG, or by Laurentis Energy Partners?

H1-SEC-204

[H1-1-1] With respect to any proposed new or modified deferral or variance accounts, please provide draft Accounting Orders. For modified deferral or variance accounts, please provide the draft as a blackline against the current accounting order.

H1-SEC-205
[H1-1-1, p.15] With respect to the Income and Other Taxes Variance Account:

a. Please provide support documents regarding the entries related to the AIIP, and specifically, please provide CCA continuity schedules with and without AIIP.
b. What is meant by the statement "Entry 1) continues to be calculated by applying the accelerated CCA rules to the forecast capital additions reflected in the EB-2013-0321 regulated hydroelectric revenue requirements, using the percentage of eligible actual regulated hydroelectric projects (for the corresponding year) as a proxy." Please provide the full calculations in your explanation.
c. Do any variances result from the impact of AIIP for CRVA eligible capital projects included in the CRVA or the Income Tax and Other Taxes Variances Account?
d. Please provide a revised version of the 2023 and 2024 balances on the basis of actual in-service additions in those years. If the answer to part (c) is the AIIP impacts for CRVA eligible projects are recorded in the CRVA, then please exclude CRVA eligible in-service additions.

H1-SEC-206
[H1-1-1, p.26] Please provide a breakdown of the costs for the feasibility assessment.

H1-SEC-207
[H1-1-1] For each account for which recovery is sought, please provide an analysis similar to that provided in EB-2023-0336 JT1.8-1.10 regarding the difference between P50 in the most recent compensation study and OPG's actual internal labour costs sought for recovery. Please use an approach similar to that sought in F4-SEC-198 and provide all account-specific supporting calculations.

H1-SEC-208
[H1-1-1, p.18] OPG proposed to defer the clearance of the hydroelectric CRVA balance to a future application, "which would provide the necessary details to support an assessment of the recoverability of any such amounts recorded over the full 2022-2026 period."

a. What is the December 31, 2024 and December 31, 2025 balance of the hydroelectric CRVA?
b. Please provide an explanation of why deferral is required to provide the necessary details to support recoverability.
c. Assuming the balance is cleared in OPG's next DVA proceeding, please provide an estimate of the incremental interest costs on the deferred balance.

H1-SEC-209
[H1-1-1, p.30] With respect to the Gross Revenue Charge Variance Account ("GRC"):

a. Is OPG aware of any discussions within the Government regarding changes to the GRC? If so, please provide details.
b. Would changes in the GRC rate be covered by the existing Income and Other Taxes Variance Account?

H1-SEC-210
[H1-1-1, p.39] With respect to the Nuclear Development Variance Account, OPG proposes that it would defer clearance of the balance related to costs for new nuclear generation facilities other than the DNNP.

a. What is the total amount of the deferred balance broken down by capital and non-capital?
b. Assuming the balance is cleared in OPG's next DVA proceeding, please provide an estimate of the incremental interest costs on the deferred balance.

H1-SEC-211
[H1-1-1, p.49] With respect to the Clarington Corporate Campus Deferral Account:

a. Please provide a breakdown of the $7M of costs included in the Account.
b. Please explain why it is reasonable for customers to pay $7M related to a project that did not proceed and was written-off.

H1-SEC-212
[H1-1-1, p.50] With respect to the Earnings Sharing Deferral Account, based on OPG's 2026 budgeted production forecast, included in this application, please provide an estimate of the year-end 2026 balance for the account. Please provide all supporting calculations.

H1-SEC-213
[H1-1-1, p.52] With respect to the Pickering B Variance Account:

a. Please provide all supporting calculations regarding the $131.1M balance as of December 31, 2024.
b. Please provide the balance of the account as of December 31, 2025.
c. Based on the 2026 budgeted production forecast, included in this application, please provide the estimated balance of the account at the end of December 31, 2026. Please provide all supporting calculations.

H1-SEC-214
[H1-1-1, p.60, 71] With respect to the proposed Change of Laws Deferral Account:

a. OPG states that the account "would record material impacts to regulated hydroelectric and nuclear costs and revenues over the IR term resulting from changes in legal and regulatory requirements". Please define "material impacts" for both OPG and DNNP.
b. If this account was in place during EB-2020-0290, please provide a full list of all changes in laws that would be eligible for recording in the account, an estimate of the specific amount, and if it would have met OPG's definition of material impact.

I1-SEC-215
[I1-1-2, p.6, Table 1] Please provide a revised version of Table 1 that shows bill impacts for all major rate classes (i.e. not just residential but also GS<50, GS>50, Large Use).

I1-SEC-216
[I1-3-2, p.6; Attachment 1, p.19] With respect to rate shaping:

a. Please confirm the amounts included in Approaches A, B and C, were provided to Innovative by OPG.
b. Please explain why OPG (or Innovative if (a) it is not confirmed) did not consider an approach where payment amounts or bill impacts increased at the same rate each year between 2027 and 2031.
c. Please provide the annual revenue requirement deferrals required to have the same annual percentage increase for each of, i) payment amounts, and ii) bill impact, for each year between 2027 and 2031.
d. What would be the incremental interest costs if the approaches discussed in part (c) were implemented. Please provide all supporting calculations.

Respectfully, submitted on behalf of the School Energy Coalition, this March 25th, 2026.

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Mark Rubenstein
Counsel for the School Energy Coalition