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

BY EMAIL

March 22, 2021

Ms. Christine E. Long
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4
Registrar@oeb.ca

Dear Ms. Long:

Re: Ontario Energy Board (OEB) Staff Interrogatories
Ontario Power Generation Inc. (OPG)
2022-2026 Payment Amounts
OEB File Number: EB-2020-0290

Please find attached OEB staff's interrogatories in the above referenced proceeding, pursuant to Procedural Order No. 1.

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

Yours truly,

Lawrie Gluck

Lawrie Gluck
Project Advisor, Generation & Transmission

Encl.

cc: All parties in EB-2020-0290

ONTARIO POWER GENERATION INC.

2022-2026 PAYMENT AMOUNTS

EB-2020-0290

OEB STAFF INTERROGATORIES

March 22, 2021

General

Letters of Comment

0-Staff-1

Question(s):

a) Please file a response to any letters of comment on the public record for this proceeding.

b) Going forward, please ensure that responses are filed to any subsequent letters that may be submitted in this proceeding. Please file responses prior to the argument phase of this proceeding.

2020 Actuals

0-Staff-2

Preamble:

OEB staff notes that Procedural Order No. 1 established April 19, 2021 as the deadline for filing interrogatory responses. OEB staff expects that OPG will have 2020 actuals available by the time that the interrogatory responses are due.

Question(s):

a) For all aspects of the application, please file updated versions of the key tables that include 2020 actuals and explain any material differences to the amounts originally presented.

b) To the extent that the 2020 actuals impact the amounts forecast for the 2021 bridge year and proposed for the 2022-2026 Custom Incentive Rate-setting (Custom IR) term, please update the amounts in the tables throughout the application. Please explain any material differences for the 2021-2026 period relative to the amounts originally forecast / proposed.

   Please reflect the 2020 actual results (and any changes to the 2021 bridge year and 2022-2026 Custom IR term) in the interrogatory responses (where applicable).

<u>Exhibit A – Administrative Documents</u>

<u>Exhibit A1 – Administration and Overview</u>

<u>Hydroelectric Payment Amount Freeze</u>

<u>A1-Staff-3</u>
Exhibit A1 / Tab 3 / Schedule 1 / p. 2

Preamble:

OPG noted that Ontario Regulation (O. Reg.) 53/05 requires that the OEB determine a base payment amount for OPG's prescribed hydroelectric facilities that is equal to the payment amount in effect on December 31, 2021. This payment amount would remain until the later of December 31, 2026 and the effective date of the OEB's next payment amount order for the regulated hydroelectric facilities.

Question(s):

a) Please confirm that OPG is seeking the OEB's approval of the hydroelectric payment amount of $43.88 / MWh for each year between 2022-2026 as part of the current application.

b) Please confirm that beyond the amounts that are eligible to be captured in the existing OEB-approved hydroelectric-related Deferral and Variance Accounts (DVAs), OPG will not seek recovery of any hydroelectric-related cost or revenue variances experienced during the 2022-2026 period.

c) Please advise whether OPG proposes that Z-factor and / or Incremental Capital Module (ICM) treatment be available during the 2022-2026 period for any potential events / projects associated with the hydroelectric business. If so, please confirm that OPG is seeking approval of the availability of these mechanisms in the current application.

Nuclear Rate-Setting Framework

A1-Staff-4

Exhibit A1 / Tab 3 / Schedule 2 / pp. 2, 8

Preamble:

OPG provided a chart that describes the proposed changes to the stretch factor (at Exhibit A1 / Tab 3 / Schedule 2 / p. 2 / Chart 1).

OPG noted that the nuclear stretch factor will reduce OPG's revenue requirement in respect of its operations OM&A costs (the sum of base, project and outage OM&A) and allocated corporate support OM&A costs, as well as nuclear operations and corporate support services in-service capital additions. The stretch factor would not apply to costs related to:

- The Darlington Refurbishment Program (DRP)
- Amounts eligible to be recorded in the Capacity Refurbishment Variance Account (CRVA)
- Amounts eligible to be recorded in the Nuclear Development Variance Account (NDVA)

Question(s):

a) Please confirm that the stretch factor approved in OPG's previous payment amounts proceeding (2017-2021 Payment Amounts Proceeding)[1] was

[1] EB-2016-0152.

determined based on the non-normalized, major operator level benchmarking results.

b) Please confirm that the stretch factor is applied to the revenue requirement associated with nuclear operations and support service in-service capital additions (as opposed to the capital in-service amounts directly).

c) Please provide a comprehensive list of all the cost categories (both OM&A and capital) to which the stretch factor is not applied. Please provide detailed rationale explaining why it is not appropriate to apply the stretch factor to each of these cost categories.

A1-Staff-5
Exhibit A1 / Tab 3 / Schedule 2 / p. 9
Exhibit F2 / Tab 1 / Schedule 1 / Attachment 2 / pp. 66-69, 86-87

Preamble:

OPG noted that, as reflected in the 2020 Nuclear Benchmarking Report, Darlington Nuclear Generating Station (NGS)'s Normalized 3-Year Total Generating Costs (TGC) / MWh is at the median (i.e. 0.3% stretch), and Pickering NGS's performance is equivalent to the fourth quintile (i.e. 0.45% stretch). OPG used a production-weighted average to determine a combined stretch factor value of 0.45%. OPG proposed that this weighted average stretch factor be used to set nuclear payment amounts until the end of 2025, when Pickering NGS will no longer be in service. For 2026, OPG proposed to use the Darlington NGS-only stretch factor of 0.3%.

Question(s):

a) Please confirm that in OPG's 2017-2021 Payment Amounts Proceeding a quartile-based approach (instead of a quintile-based approach) was used to determine the relevant stretch factor that is applicable to OPG.

b) Please confirm that the 2020 Nuclear Benchmarking Report provides the benchmarking results on a quartile basis.

c) Please discuss the approach applied to determine which quantile OPG's NGSs are in relative to the peer group. Please reference the 2020 Nuclear Benchmarking report in the response.

d) Using the station level benchmarking results, please confirm that on a non-normalized and quintile-based approach, both Pickering NGS and Darlington NGS are in quintile 5 (0.6% stretch factor) (Exhibit F2 / Tab 1 / Schedule 1 / Attachment 2 / p. 69).

e) Using the station level benchmarking results, please confirm that on a normalized and quartile-based approach, Pickering NGS is in quartile 4 (0.6% stretch factor) and Darlington NGS is in quartile 3 (0.45% stretch factor) (Exhibit F2 / Tab 1 / Schedule 1 / Attachment 2 / p. 68).

f) Using the station level benchmarking results, please confirm that on a non-normalized and quartile-based approach, both Pickering NGS and Darlington NGS are in quartile 4 (0.6% stretch factor) (Exhibit F2 / Tab 1 / Schedule 1 / Attachment 2 / p. 69).

g) Using the major operator level benchmarking results (Exhibit F2 / Tab 1 / Schedule 1 / Attachment 2 / p. 88), please provide the following:

   i. The quartile that applies to OPG based on the normalized results

   ii. The quartile that applies to OPG based on the non-normalized results

   iii. The quintile that applies to OPG based on the normalized results

   iv. The quintile that applies to OPG based on the non-normalized results

A1-Staff-6
Exhibit A1 / Tab 3 / Schedule 2 / pp. 10, 12

Preamble:

In Chart 3 at Exhibit A1 / Tab 3 / Schedule 2 / p. 10, OPG provided its derivation of the production-weighted average stretch factor.

In Chart 4 at Exhibit A1 / Tab 3 / Schedule 2 / p. 12, OPG provided the revenue requirement impact of applying the proposed stretch factor to the relevant cost categories.

Question(s):

a) Please provide detailed calculations supporting the annual stretch reductions to nuclear revenue requirement for each year during the 2023-2026 period. Specifically, for 2025, please quantify (and show the calculation for) the removal of the Pickering Outage OM&A-related stretch reduction carry-forward. For 2026, please quantify (and show the calculation for) the removal of the entirety of the Pickering NGS-related stretch reduction carry-forward.

b) Please provide a revised version of Chart 3 at Exhibit A1 / Tab 3 / Schedule 2 / p. 10 based on Darlington NGS being applied a 0.45% stretch factor and Pickering NGS being applied a 0.6% stretch factor. Please also provide a revised version of Chart 4 at Exhibit A1 / Tab 3 / Schedule 2 / p. 12 reflecting the resulting production-weighted average stretch factor for 2023-2025 and a 0.45% stretch factor applicable to Darlington NGS in 2026. Please provide the supporting calculations.

c) Please provide a revised version of Chart 4 at Exhibit A1 / Tab 3 / Schedule 2 / p. 12 reflecting a 0.6% stretch factor in all years (2023-2026). Please provide the supporting calculations.

A1-Staff-7
Exhibit A1 / Tab 3 / Schedule 2 / pp. 12-13
EB-2016-0152 / Decision and Order / p. 138

Preamble:

OPG noted that it is not proposing a nuclear industry productivity adjustment as part of the proposed X-factor. OPG stated that the nature and scale of work planned by OPG over the Custom IR term means that past productivity trends would not be a reasonable indicator of predicted productivity for OPG.

In its Decision and Order with respect to OPG’s 2017-2021 Payment Amounts Proceeding, the OEB stated that it agrees that determining an appropriate nuclear generation industry productivity factor for the test period would be a challenge. The absence of a productivity factor for the current Custom IR plan does not mean that future applications should have the same structure. The OEB’s expectations regarding an independent productivity study continue, and OPG should be prepared to file work plans for this study when the DRP approaches its conclusion.

Question(s):

a) Please advise when the OEB can expect that OPG will file a nuclear industry productivity study.

A1-Staff-8
Exhibit A1 / Tab 3 / Schedule 2 / p. 13
Exhibit I1 / Tab 1 / Schedule 1 / p. 2

Preamble:

OPG proposed to continue its existing off-ramp provision (+/- 300 basis points deadband for determining whether a regulatory review should be initiated) in the 2022-2026 Custom IR term.

OPG achieved earnings in excess of the OEB-approved return on equity (ROE) in 2019 and forecasts that it will do so again in 2020 and 2021.

Question(s):

a) Please provide OPG’s views on the inclusion of an asymmetrical earnings sharing mechanism (ESM) for the 2022-2026 Custom IR term.

b) Please discuss whether it is possible to apply the ESM only to earnings generated by the nuclear business or could only be applied for earnings generated by the entire regulated business (both hydroelectric and nuclear).

c) Please provide OPG’s views on an ESM structure whereby: (a) the first 100 basis points of earnings in excess of the OEB-approved ROE is to the benefit of OPG’s shareholder; (b) earnings between 100-200 basis points above the OEB-approved ROE are shared 50:50 with ratepayers; and (c) earnings in excess of 300 basis points above the OEB-approved ROE are shared 90:10 to the benefit of ratepayers.

A1-Staff-9
Exhibit A1 / Tab 3 / Schedule 2 / p. 13

Preamble:

OPG proposed that unforeseen events affecting the nuclear business continue to be addressed through an accounting order process, subject to the $10 million regulatory materiality threshold that has historically applied to OPG and which was accepted for this purpose in OPG's 2017-2021 Payment Amounts Proceeding.

Question(s):

a) Please confirm that OPG is referring to events that would be subject to the OEB's Z-factor policy.

b) Please provide examples of unforeseen events that may be subject to the above noted accounting order process.

c) Please further describe the accounting order process.

A1-Staff-10
Exhibit A1 / Tab 1 / Schedule 1 / p. 3
Exhibit A1 / Tab 3 / Schedule 2

Preamble:

With the exception of a standalone application to address the potential impacts of the Independent Electricity System Operator's (IESO) Market Renewal Program (MRP), OPG did not discuss any other applications that it may file during the 2022-2026 Custom IR term.

Question(s):

a) Please provide a list of the applications that OPG expects to file during the 2022-2026 Custom IR term (including standalone DVA disposition applications). Please include the expected timing for the filing of these applications.

A1-Staff-11
Exhibit A1 / Tab 1 / Schedule 1 / p. 3

Preamble:

OPG noted that it expects that the IESO will complete the final design and implementation phase of its MRP during the 2022-2026 Custom IR term. Given the inherent uncertainty associated with the final design and implementation of the MRP, OPG noted that the current application does not include any rate-setting impacts resulting from the MRP. OPG stated that it intends to file a separate application to address any such impacts once the IESO has completed the detailed design phase and advanced the implementation phase of the MRP.

OPG further noted that it does not expect that the MRP will require any changes to the structure of OPG's base payment amounts. However, the equations underlying the Hydroelectric Incentive Mechanism (HIM) may need to be adjusted to reflect the settlement of the new day-ahead market (DAM) and the real-time market.

OEB staff notes that the IESO issued its DAM High-Level Design document in August 2019 and, as identified on the IESO's Detailed Design web page, the final MRP Energy Detailed Design documents were posted on January 28, 2021 (after this application was filed).

The DAM High-Level Design document stated that in the event that contracted or rate-regulated resources do not have the right incentives to participate in the DAM prior to the implementation of the renewed market, existing offer obligations will be maintained as a transitionary measure.

Question(s):

a) Please further discuss the expected changes to the HIM that will result from the implementation of the MRP.

b) Given that OPG's payment amounts have been established within the context of only a real-time market to date, and a financially binding DAM is being introduced as part of the MRP, why does OPG believe that the potential implications of the MRP are limited to changes to the HIM?

c) Please provide OPG’s position on whether the current payment amount design would operate to disincentivize OPG from participating in the DAM, or participating on a less than fully efficient basis. Please discuss in detail.

d) If the potential implications of the MRP are not limited to the HIM, please explain what other aspects of OPG’s hydroelectric and nuclear payment amounts might be impacted.

e) Please discuss any potential changes to both hydroelectric and nuclear-related DVAs resulting from the implementation of the MRP. Please also advise whether OPG expects that new DVAs will need to be established for either the hydroelectric or nuclear businesses resulting from the implementation of the MRP.

f) Please confirm that OPG does not expect any changes to the revenue requirement underpinning the nuclear payment amounts sought for approval in the current application resulting from the implementation of the MRP. For example, if the MRP were to result in a change to OPG’s risk profile, please confirm that OPG would not seek changes, in the standalone MRP application, to its capital structure or cost of capital.

g) Please confirm that OPG does not expect any changes to nuclear payment amount design sought for approval in the current proceeding resulting from the implementation of the MRP. Specifically, please confirm that OPG does not intend to seek a change to the calculation of nuclear payment amounts (i.e. revenue requirement net of stretch factor – deferred revenue (for rate smoothing) / forecast production).

h) Please provide OPG’s position on the need for the OEB, in the current application, to establish the scope (i.e. the aspects of the payment amounts and / or deferral and variance accounts that are subject to change) for the forthcoming standalone MRP application.

Performance Scorecard and Annual Reporting

A1-Staff-12
Exhibit A1 / Tab 3 / Schedule 2 / pp. 14-15
Exhibit A1 / Tab 3 / Schedule 2 / Attachment 1
EB-2016-0152 / Decision and Order / December 28, 2017 / p. 151

Preamble:

In its Decision and Order in OPG's 2017-2021 Payment Amounts Proceeding, the OEB set out requirements for nuclear performance reporting. The OEB directed OPG to report on Unit Capability Factor (UCF), Nuclear Performance Index (NPI) and TGC for the nuclear business. The OEB further directed that results related to OPG's nuclear business be reported on a normalized and non-normalized basis for the years impacted by DRP.

In the current proceeding, OPG proposes to continue to include normalized TGC / MWh for the nuclear facilities in its scorecard as well as continue reporting on the non-normalized TGC / MWh.

For the proposed nuclear performance scorecard, targets and actual performance results are reported on a single-year basis, unless otherwise noted. In addition, targets and actual performance results for Pickering NGS and Darlington NGS are proposed to be reported separately, but a combined nuclear performance result for UCF, NPI, and TGC / MWh will also be provided.

Question(s):

a) In reviewing the proposed scorecard for nuclear performance, it appears that OPG is proposing to report UCF and NPI on a non-normalized basis. Please confirm / clarify how OPG intends to report on these measures. If proposing to only report UCF and NPI on a non-normalized basis, please provide reasoning with consideration to the direction provided by the OEB in its 2017-2021 Payment Amounts Proceeding for nuclear performance reporting.

b) Please clarify how OPG intends to report on nuclear performance measures following the shutdown of Pickering NGS in 2025.

A1-Staff-13
Exhibit A1 / Tab 3 / Schedule 2 / pp. 14-15
Exhibit D2 / Tab 2 / Schedule 8 / p. 16
EB-2016-0152 / Decision and Order / December 28, 2017 / pp. 146-151

Preamble:

The current timelines in which OPG files various reports with the OEB are as follows:

Report	Report Filing Frequency	Report Filing Timeline
Financial and Operating Reports	Annually	Filed by July 31
Hydroelectric Performance Report		Filed by April 30
Nuclear Performance Report		Initial report filed by April 30, then re-filed by November 30 when benchmark quartile results are available
DRP Report		Filed in December

Question(s):

a) For each of the reports that OPG files with the OEB (i.e. the reports noted in the above table), would OPG have any objection(s) to filing redacted versions of each report with the intervenors to this proceeding going forward? If so, please explain why.

b) Would OPG have any objection(s) to redacted versions of each report being posted publicly on the OEB's website going forward? If so, please explain why.

c) For the financial and operating reports, please explain when, at the earliest, OPG is in a position to provide initial results prior to filing the finalized report with the OEB.

OPG Responses to OEB Directives and Undertakings from Previous Proceedings

A1-Staff-14

Exhibit A1 / Tab 11 / Schedule 1 / p. 2
Exhibit H1 / Tab 1 / Schedule 1 / p. 12

Preamble:

Pursuant to the OEB-approved settlement proposal in OPG's 2019 Hydroelectric Payment Amount Adjustment and Deferral Account Disposition proceeding[2], OPG filed a forward-looking study to assess OPG's management of its generating facilities in relation to Surplus Baseload Generation (SBG) conditions in the current application. The study explains that OPG already takes a number of actions that mitigate SBG conditions. The study also confirmed that there are not any viable additional actions OPG can take in response to SBG conditions beyond those currently in place without adversely impacting the economics and efficient operation of the IESO's energy market. OPG noted that the IESO was consulted in the preparation of the study and did not have any concerns with its main conclusions.

Question(s):

a) Please confirm that OPG is not seeking any changes to the treatment of SBG in the current application.

b) Please advise whether the MRP may have an impact on the management of OPG's hydroelectric generation facilities with respect to SBG. If so, please discuss whether any changes to the treatment of SBG will be required in the expected standalone MRP application.

[2] EB-2018-0243.

A2 – Finance

Financial Summary

A2-Staff-15

Exhibit A2 / Tab 1 / Schedule 1
Exhibit A2 / Tab 1 / Schedule 1 / Attachment 2

Preamble:

OEB staff notes that the financial and operating results for the year ended December 31, 2020, including the consolidated Audited Financial Statements (AFS) and Management Discussion and Analysis (MDA), were issued on March 11, 2021.

Question(s):

a) Please file the 2020 consolidated AFS and MDA on the record of this proceeding.

b) If available, please file the 2020 financial statements for the prescribed facilities on the record of this proceeding.

A2-Staff-16

Exhibit A2 / Tab 1 / Schedule 1 / Attachment 1 / pp. 64-65
Exhibit A2 / Tab 1 / Schedule 1 / Attachment 2 / pp. 13-14

Preamble:

In OPG's unaudited financial statements as of September 30, 2020 and audited financial statements as of December 31, 2019, new accounting standards effective from 2018, 2019, or 2020, and their implication on OPG's financial statements, are discussed.

Question(s):

a) Please explain whether there are any new accounting standards effective 2021 and beyond that will have an impact on the application.

b) If so, please identify and explain the new accounting standard(s) and its impact on the application, including quantification of the revenue requirement impact.

A2-Staff-17
Exhibit A2 / Tab 1 / Schedule 1 / Attachment 2 / pp. 13-14

Preamble:

In OPG's 2019 audited financial statements, under New Accounting Standards effective in 2019 – Lease Accounting, OPG recognized right-of-use assets and operating lease liabilities of $70 million and $74 million, respectively, as at January 1, 2019.

Questions:

a) For leases that existed, or were entered into, during OPG's 2017-2021 Payment Amounts application period that will still have term remaining as of January 1, 2022, please provide a table to include:

    i. A listing of these leases (aggregated by category, if necessary, for practical purposes)

    ii. The classification of these leases as operating or finance leases for regulatory purposes in the 2017-2021 Payment Amounts application

    iii. The treatment of the associated costs as OM&A or rate base in the 2017-2021 Payment Amounts application (including the amount)

    iv. The classification of these leases as operating or finance leases for regulatory purposes in the current application

    v. The treatment of the associated costs as OM&A or rate base in this application, including the amount

b) Please explain OPG's rationale for its inclusion of associated lease costs as OM&A or rate base in the current application for each of the leases.

c) Please quantify the revenue requirement difference between classifying these costs as operating versus capital.

d) If there has been a change in the accounting treatment of leases that existed, or were entered into, during OPG's 2017-2021 Payment Amounts Proceeding period that will still have term remaining as of January 1, 2022, please explain

OPG's proposal to address the revenue requirement differences for ratemaking purposes.

Business Planning and Budgeting

Impact of COVID-19 Pandemic

A2-Staff-18
Exhibit A2 / Tab 2 / Schedule 1 / p. 8
Exhibit D2 / Tab 2 / Schedule 1 / pp. 5-6
Exhibit H1 / Tab 1 / Schedule 1 / p. 37

Preamble:

OPG noted that the 2020-2026 Business Plan includes the impact of the actions taken to date in response to the COVID-19 pandemic, including a deferred DRP schedule and other associated changes in Darlington NGS outages, and certain incremental expenditures being incurred over the course of the pandemic.

OPG noted that the COVID-19 pandemic is currently estimated to have resulted in a $150 million increase in DRP costs. OPG stated that it is not seeking approval of any COVID-19 pandemic-related costs associated with the DRP in this application, and none are included in the in-service additions presented. Any ultimate variance to the $12.8 billion total DRP budget caused by the COVID-19 pandemic would be tracked separately and addressed through the CRVA in a future proceeding.

OPG also noted that the Impacts Arising from the COVID-19 Emergency Deferral Account (CEDA) was established by the OEB in its March 25, 2020 accounting order in acknowledgement that electricity and natural gas distributors may incur incremental costs as a result of the COVID-19 emergency. OPG noted that, in an April 29, 2020 letter, the OEB confirmed the applicability of the account to OPG and electricity transmitters. The account is effective March 24, 2020. OPG did not seek disposition of any balances recorded in the account in this application.

Question(s):

a) Please provide a breakdown of the $150 million impact on the DRP associated with the COVID-19 pandemic. Specifically, please describe the drivers of the incremental costs and advise whether the $150 million impact is a capital amount.

b) Please advise whether the $150 million impact on the DRP associated with the COVID-19 pandemic was incurred in 2020 or also includes estimates for 2021 and future years. If it reflects an estimate over multiple years, please provide the amount by year (and cost type – capital or OM&A) and provide the amount that is currently recorded in the CRVA.

c) Please explain why OPG is tracking the $150 million impact on the DRP associated with the COVID-19 pandemic in the CRVA (as opposed to the CEDA).

d) For the following categories of costs, please advise whether there are any 2020 or forecast 2021 impacts related to the COVID-19 pandemic recorded (or expected to be recorded) in the CRVA, the CEDA, or any other DVAs. Please specify which account includes the relevant balances and also quantify the amount already recorded and / or forecast to be recorded. Please also discuss the drivers of the COVID-19 pandemic related costs recorded in the CRVA, CEDA, or any other DVAs.

i. CRVA eligible nuclear capital costs (non-DRP)

ii. CRVA eligible nuclear OM&A costs (non-DRP)

iii. Non-CRVA eligible nuclear capital costs

iv. Non-CRVA eligible nuclear OM&A costs

v. CRVA eligible hydroelectric capital costs

vi. CRVA eligible hydroelectric OM&A costs

vii. Non-CRVA eligible hydroelectric capital costs

viii. Non-CRVA eligible hydroelectric OM&A costs

Please also provide the total COVID-19 impact cost already recorded in the CRVA, CEDA and any other DVAs (inclusive of the $150 million impact of the COVID-19 pandemic on the DRP).

e) Please advise whether OPG intends to record any new COVID-19 pandemic related costs in either the CRVA or CEDA after December 31, 2021. If so, please explain why and quantify the expected balances.

f) For the following categories of capital costs, please advise whether the proposed 2022-2026 rate base amounts include any COVID-19 pandemic related costs. Please quantify the capital in-service additions associated with the impact of the COVID-19 pandemic included in rate base in each year of the proposed Custom IR term. Please also discuss the drivers of the COVID-19 pandemic related in-service additions included in rate base.

   i. CRVA eligible nuclear capital costs (non-DRP)

   ii. Non-CRVA eligible nuclear capital costs

g) For the follow categories of OM&A costs, please advise whether the proposed 2022-2026 OM&A budgets include any COVID-19 pandemic related costs. Please quantify the OM&A costs associated with the COVID-19 pandemic included in the revenue requirement in each year of the proposed Custom IR term. Please also discuss the drivers of the COVID-19 pandemic related OM&A costs included in the OM&A budgets.

   i. CRVA eligible nuclear OM&A costs (non-DRP)

   ii. Non-CRVA eligible nuclear OM&A costs

h) Please confirm that the impact of the COVID-19 pandemic has been reflected in OPG's nuclear production forecast for each year of the 2022-2026 Custom IR term.

A2-Staff-19
Exhibit A2 / Tab 2 / Schedule 1 / Attachment 1 / pp. 12-14
Exhibit I1 / Tab 1 / Schedule 1 / p. 2
Exhibit I1 / Tab 1 / Schedule 1 / Tables 4-5
EB-2020-0246 / Notice of Proceeding and Accounting Order / November 9, 2020 / Schedule A

Preamble:

OPG's 2020-2026 Business Plan sets out its forecast of net income during the 2020-

2026 business planning period and discusses the reasons for the variations in net income.[3]

OPG provided its actual and forecast ROE for 2017-2021 (for the combined regulated business – both hydroelectric and nuclear) as set out in the following table.

	2017	2018	2019	2020	2021	Average
OPG ROE	5.91%	10.69%	15.61%	12.67%	10.24%	11.10%
OEB-Approved	9.16%	9.16%	9.16%	9.16%	9.16%	9.16%

OPG provided an explanation of the expected earnings variances for 2020 and 2021 in its 2019 Regulatory Return filing to the OEB.[4]

At the time of its 2019 Regulatory Return filing, OPG forecasted an ROE of 12.8% for 2020 and an ROE of 9.0% for 2021 (now updated to 12.67% for 2020 and 10.24% for 2021 in the application). Based on the ROE estimates available at the time of OPG's 2019 Regulatory Return filing, OPG explained that its response measures to COVID-19 are expected to have an impact on OPG's regulated ROE performance for 2020 and 2021. The single largest such impact related to a planned deferral of a Darlington NGS Unit 1 outage from the Fall of 2020 to 2021 to support the revised start date of the Darlington NGS Unit 3 refurbishment. OPG noted that, while the change in the Unit 1 outage timing is expected to increase the 2020 ROE above the 300 basis points deadband, to 12.8%, it will have a corresponding negative effect on the 2021 ROE, which OPG expects to be slightly below the OEB-approved ROE, at 9.0%.

Question(s):

a) Please file the redacted version of the 2019 Regulatory Return filing on the record of this proceeding (including the cover letter).

b) For 2020, please update Table 4 at Exhibit I1 / Tab 1 / Schedule 1 to show the impact of the COVID-19 pandemic on each major line item for the nuclear business (i.e. nuclear production, indicated nuclear production revenue, total nuclear expenses, total nuclear cost of capital excluding ROE, nuclear deferral account adjustments, income tax and regulatory ROE).

[3] Note that some of the net income information provided in the 2020-2026 Business Plan was filed under confidential cover.
[4] EB-2020-0248 / Notice of Proceeding and Accounting Order / November 9, 2020 / Schedule A.

c) For 2021, please update Table 5 at Exhibit I1 / Tab 1 / Schedule 1 to show the impact of the COVID-19 pandemic on each major line item for the nuclear business (i.e. nuclear production, indicated nuclear production revenue, total nuclear expenses, total nuclear cost of capital excluding ROE, nuclear deferral account adjustments, income tax and regulatory ROE).

d) Please explain how the COVID-19 pandemic-related costs that are recorded and / or tracked in OPG's DVAs are reflected in Tables 4 and 5 at Exhibit I1 / Tab 1 / Schedule 1.

e) Please provide a detailed explanation of the corrections that were made to Table 4 at Exhibit I1 / Tab 1 / Schedule 1 in the corrected evidence and confirm that those corrections impacted the estimated 2020 ROE.

f) Please confirm that the corrections made to Table 5 at Exhibit I1 / Tab 1 / Schedule 1 were for presentation purposes only and there were no errors that impacted the estimated 2021 ROE.

g) For the hydroelectric business segment, please quantify the impact of the COVID-19 pandemic on revenues, costs and regulatory ROE for each year of 2020 and 2021.

h) Please provide a detailed explanation of the drivers for the forecasted 2020 and 2021 earnings in excess of the OEB-approved ROE (for the combined regulated business).

i) Please explain the changes in the estimated ROE for 2020 and 2021 as presented in the application relative to the information provided in the cover letter for the 2019 Regulatory Return filing.

Business Planning Process

A2-Staff-20
Exhibit A2 / Tab 2 / Schedule 1 / p. 10

Preamble:

OPG noted that when presenting information that requires direct continuity of balances from 2020 (e.g. rate base values), OPG used the 2020 current forecast information from the 2020-2026 Business Plan, rather than the restated budget.

Question(s):

a) Please provide a list of the costs that are based on the 2020 current forecast information.

b) Please provide the timing of when the 2020 current forecast information became available and explain the nature of the updates that are included in the 2020 current forecast information (relative to the restated budget).

Customer Engagement Study

A2-Staff-21
Exhibit A2 / Tab 2 / Schedule 1 / Attachment 4 / p. 6

Question(s):

a) Please advise whether the same 3,504 residential and 312 business customers who provided their input to Phase 1 of the customer engagement process also provided their input to Phase 2 of the process.

b) Please provide the rationale for seeking the input of approximately 58% more residential customers and approximately 70% more business customers in Phase 2 of the customer engagement process versus Phase 1 of the process.

A2-Staff-22
Exhibit A2 / Tab 2 / Schedule 1 / Attachment 4 / pp. 14-17

Question(s):

a) Please identify any efforts undertaken to ensure that the residential and business customers who participated in the customer engagement process represent a valid statistical sample of Ontario’s population and business sectors.

A2-Staff-23
Exhibit A2 / Tab 2 / Schedule 1 / Attachment 4 / pp. 7, 9-11

Question(s):

a) The Innovative Research Group report stated that “most Ontarians know little about OPG and the energy system more broadly.” Considering this, please elaborate on the validity and applicability of the survey results with regard to OPG's business planning process. Further, please discuss the validity and applicability of the survey results received on the complex topics presented in Phase 2 of the process (i.e. rate smoothing, Niagara frequency conversion, Darlington vapour recovery system improvement, air compressor replacement & crane group project).

b) Please describe the process used to select the Business Decisions and Investment Trade-off topics presented to participants in Phase 2 of the customer engagement process.

c) Please comment on the value and insights OPG gained from the completion of this customer engagement process.

d) Please comment on whether OPG currently intends to complete additional or supplemental customer engagements in support of business planning activities in the future.

Exhibit B – Rate Base

Exhibit B1 / B3 – Nuclear Rate Base

B1-Staff-24

Exhibit B1 / Tab 1 / Schedule 1 / p. 2 / Footnote 1

Preamble:

Footnote 1 states that the $84.5 million amount is calculated as: Exhibit B3 / Tab 3 / Schedule 1 / Table 2 / Column (c) / Line 2 less Exhibit B3 / Tab 4 / Schedule 1 / Table 2 / Column (d) / Line 18.

OEB staff was unable to reproduce the $84.5 million value based on the citations provided in Footnote 1.
Question(s):

a) Please provide a table that shows how the $84.5 million value was derived and includes the numbers used in the derivation. Where applicable, please include citations to applicable tables and cells elsewhere in the application.

B1-Staff-25
Exhibit B1 / Tab 1 / Schedule 1 / p. 3

Preamble:

OPG stated that by 2021, the non-DRP net plant rate base is projected to be $558.1 million higher than the OEB-approved amount, primarily due to cumulatively higher non-DRP capital in-service additions for the Darlington NGS.

Question(s):

a) Please provide a table that compares OEB-approved in-service amounts to actual in-service amounts between 2016 and 2021, distinguishing between DRP and non-DRP values.

b) With reference to the table requested in (a) above, please clarify how the $558.1 million variance by 2021 was derived.

c) Please confirm whether "by 2021" in the above quote means the end of 2021 or end of 2020. Please also confirm whether the $558.1 million is included in the opening 2021 or 2022 rate base amount.

B1-Staff-26
Exhibit B1 / Tab 1 / Schedule 1 / p. 3
Exhibit B3 / Tab 1 / Schedule 1 / Tables 1 and 2
Exhibit B3 / Tab 2 / Schedule 1 / Table 2

Preamble:

The first reference above states adjusting for the D2O Storage Project not included in the 2017-2021 rate base and excluding nuclear asset retirement costs (ARC), rate base is forecasted to be $650.3 million higher than the OEB-approved value by 2021. On the same basis, for 2019, the actual rate base is $340.8 million higher than the OEB-approved value.

OPG did not provide citations to show how the values above were derived and OEB staff was unable to reproduce the values above based on the second and third references above.

Question(s):

a) Please provide a table that shows how the $650.3 million and $340.8 million values were derived and includes the numbers used in the derivations. Where applicable, please include citations to applicable tables and cells elsewhere in the application.

B1-Staff-27

Exhibit B1 / Tab 1 / Schedule 1 / p. 5

Preamble:

OPG stated that a downward adjustment to the gross plant and accumulated depreciation and amortization amounts is included in the continuity schedules for 2022 to effect OPG's proposal of limiting the DRP-related net plant in rate base for projects completed prior to 2022 to the values approved in OPG's 2017-2021 Payment Amounts Proceeding as of December 31, 2021.

Question(s):

a) Please advise where in the evidence the downward adjustment, referenced above, is found and please state the value of the downward adjustment.

b) Please provide the derivation of the downward adjustment value.

B1-Staff-28

Exhibit B1 / Tab 1 / Schedule 1 / Chart 1
Exhibit B3 / Tab 3 / Schedule 1 / Tables 1 and 2
Exhibit D2 / Tab 1 / Schedule 3 / Table 4b
Exhibit D2 / Tab 2 / Schedule 9 / Tables 5a and 5b
Exhibit D3 / Tab 1 / Schedule 2 / Tables 5a and 5b

Preamble:

Based on the above references, OEB staff derived the chart below that shows nuclear capital in-service additions between 2016 and 2026.

Line No.		(a) 2016 Actual	(b) 2017 Actual	(c) 2018 Actual	(d) 2019 Actual	(e) 2020 Budget	(f) 2021 Budget	(g) 2022 Plan	(h) 2023 Plan	(i) 2024 Plan	(j) 2025 Plan	(k) 2026 Plan
1	Nuclear operations capital projects (1)	286.4	464.4	390.3	326.1	282.2	331.8	434.3	461.6	489.0	477.3	348.3
2	Darlington Refurbishment Program (2)	324.4	305.9	34.5	336.9	4,796.6	8.6	0.0	1.4	2,505.5	1,907.3	2,028.3
3	Support services capital projects entering nuclear rate base (3)	8.9	8.0	33.3	42.0	43.8	58.8	68.3	38.0	34.4	47.8	30.9
4	**Total nuclear in-service additions, excl. ARC** (4)	**619.6**	**778.2**	**458.0**	**705.1**	**5,122.7**	**399.2**	**502.6**	**501.0**	**3,028.9**	**2,432.5**	**2,407.5**

Notes: OEB staff based on: (1) D2-1-3 Table 4a, line 26 and Table 4b, lines 38 & 52; (2) D2-2-9 Table 5a, line 20 and Table 5b, lines 33 & 46; (3) D3-1-2 Table 5a, sum of lines 9 & 11; Table 5b, sum of lines 17 & 19 and sum of lines 25 & 27; (4) B3-3-1 Tables 1 & 2, col. (b); and B1-1-1 Chart 1.

Question(s):

a) Please confirm the values in the chart above.

b) If OEB staff's calculation is incorrect, please provide a corrected version. Where applicable, please include citations to applicable tables and cells elsewhere in the application.

B1-Staff-29

Exhibit B1 / Tab 1 / Schedule 1 / Table 1
Exhibit B3 / Tab 1 / Schedule 1 / Tables 1 and 2

Preamble:

OEB staff derived the following rate base table from the references above.

Prescribed Facility Category/Rate Base Item	Line No.		(a) 2016 Actual	(b) 2017 Actual	(c) 2018 Actual	(d) 2019 Actual	(e) 2020 Budget	(f) 2021 Budget	(g) 2022 Plan	(h) 2023 Plan	(i) 2024 Plan	(j) 2025 Plan	(k) 2026 Plan
Darlington NGS	1	Gross	1,152.4	1,339.4	1,580.3	1,874.8	2,100.2	2,377.7	2,692.2	3,166.1	3,660.4	4,081.1	4,511.8
	2	Accumulated Depreciation	392.3	427.5	468.0	516.1	577.9	656.0	748.5	860.1	992.4	1,144.0	1,310.9
	3	Net	760.1	911.9	1,112.2	1,358.7	1,522.3	1,721.7	1,943.7	2,305.9	2,668.0	2,937.1	3,200.9
Darlington Refurbishment Program	4	Gross	362.3	638.0	767.7	792.9	3,589.1	5,587.9	5,457.6	5,458.3	7,963.8	9,315.6	10,294.5
	5	Accumulated Depreciation	21.5	43.4	74.1	108.2	186.8	341.2	478.2	643.1	851.2	1,127.1	1,445.3
	6	Net	340.8	594.6	693.6	684.7	3,402.3	5,246.7	4,979.4	4,815.2	7,112.6	8,188.5	8,849.1
Heavy Water Storage Facility (D2O)	7	Gross	14.6	174.6	174.6	201.4	502.4	509.3	509.3	509.3	509.3	509.3	509.3
	8	Accumulated Depreciation	0.7	3.3	8.1	13.4	23.6	38.4	53.4	68.4	83.3	98.3	113.3
	9	Net	13.9	171.3	166.5	188.0	478.9	470.9	455.9	441.0	426.0	411.0	396.1
Pickering NGS	10	Gross	2,235.2	2,346.6	2,473.3	2,538.7	2,596.8	2,643.8	2,663.5	2,670.5	2,671.6	2,672.0	2,672.1
	11	Accumulated Depreciation	1,570.7	1,730.4	1,875.1	1,994.5	2,118.7	2,255.1	2,402.7	2,517.6	2,594.8	2,633.3	2,633.4
	12	Net	664.5	616.2	598.2	544.2	478.1	388.7	260.8	152.9	76.8	38.7	38.7
Operations and Project Support	13	Gross	384.0	422.6	429.3	413.8	445.7	509.6	568.3	670.1	714.2	752.9	782.7
	14	Accumulated Depreciation	309.8	340.8	326.9	314.7	348.9	381.6	418.0	457.6	499.7	542.0	583.2
	15	Net	74.2	81.8	102.4	99.1	96.8	128.0	150.3	212.4	214.5	210.9	199.5
Nuclear, Excluding Asset Retirement Costs	16	Gross	4,148.6	4,921.3	5,425.2	5,821.6	9,234.3	11,628.4	11,891.0	12,474.3	15,519.4	17,330.9	18,770.4
	17	Accumulated Depreciation	2,295.1	2,545.4	2,752.3	2,946.9	3,255.9	3,672.4	4,100.9	4,546.8	5,021.4	5,544.6	6,086.1
	18	**Net**	**1,853.5**	**2,375.9**	**2,672.9**	**2,874.6**	**5,978.4**	**7,956.0**	**7,790.1**	**7,927.5**	**10,497.9**	**11,786.3**	**12,684.3**
Asset Retirement Costs	19	Gross	2,421.7	2,163.3	2,307.0	2,307.0	2,307.0	2,307.0	2,307.0	2,307.0	2,307.0	2,307.0	2,307.0
	20	Accumulated Depreciation	1,596.0	1,658.2	1,736.4	1,818.5	1,900.7	1,982.8	2,065.0	2,131.3	2,181.8	2,208.9	2,212.4
	21	**Net**	**825.7**	**505.1**	**570.6**	**488.5**	**406.3**	**324.1**	**242.0**	**175.7**	**125.1**	**98.1**	**94.6**
Nuclear, Including Asset Retirement Costs	22	Gross	6,570.2	7,084.5	7,732.2	8,128.6	11,541.2	13,935.3	14,197.9	14,781.3	17,826.3	19,637.9	21,077.4
	23	Accumulated Depreciation	3,891.0	4,203.6	4,488.6	4,765.4	5,156.6	5,655.1	6,165.8	6,678.1	7,203.2	7,753.6	8,298.5
	24	**Net**	**2,679.2**	**2,880.9**	**3,243.5**	**3,363.2**	**6,384.7**	**8,280.1**	**8,032.1**	**8,103.1**	**10,623.0**	**11,884.3**	**12,778.9**
Working Capital	25	Cash Working Capital	0.3	11.5	2.3	-4.1	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8
	26	Fuel Inventory	290.1	270.6	259	224.7	190.9	190.6	208.7	209.8	189.8	185.9	178.5
	27	Materials & Supplies	434	446.4	449.6	463.6	494.8	508.7	517.3	513.5	485.6	435.9	392.5
	28	**Total Working Capital**	**724.4**	**728.5**	**710.9**	**684.2**	**647.9**	**661.5**	**688.2**	**685.5**	**637.6**	**584**	**533.2**
Net Nuclear, Including Net Asset Retirement Costs and Working Capital	29	**Total**	**3,403.6**	**3,609.5**	**3,954.4**	**4,047.2**	**7,032.6**	**8,941.8**	**8,720.4**	**8,788.7**	**11,260.7**	**12,468.5**	**13,312.0**

Question(s):

a) Please confirm the accuracy of OEB staff's chart or provide a corrected version. If a corrected version is provided, please include citations to applicable tables and cells elsewhere in the application.

B1-Staff-30

Exhibit B1 / Tab 1 / Schedule 1 / p. 5

Preamble:

OPG stated that the net fixed / intangible asset portion of rate base is determined using a mid-year average methodology. For large in-service additions or adjustments, where the in-service addition amount or the amount of an adjustment exceeds $50 million, the month in which the addition or adjustment is reflected is used, instead of a mid-year average, to improve accuracy. There are nine nuclear in-service additions forecasted during the bridge years and Custom IR term in the amount of greater than $50 million.

Question(s):

a) Please provide rationale supporting the $50 million cut-off applied to in-service additions for using a monthly approach to calculating rate base.

b) Please confirm that the $50 million cut-off is applied to the annual in-service addition amount (and is not based on the total cost of the capital project).

c) For any capital project (both DRP-related and nuclear operations-related) that has an in-service addition amount in any year during the 2022-2026 Custom IR term that is greater than $5 million, please provide:

    i. The name of the project

    ii. The in-service amount in each year of the 2022-2026 Custom IR term where the in-service amount is greater than $5 million

    iii. The month in which the greater than $5 million asset is placed in service for each year noted in the response to part (c – ii)

B3-Staff-31

Exhibit B3 / Tab 4 / Schedule 1 / Tables 1-2

Question(s):

a) Please clarify whether the adjustments in column (c) in Table 1 and column (d) in Table 2 at Exhibit B3 / Tab 1 / Schedule 1 are adjustments to the opening balance or whether they occur within the year. If some of the adjustments are to the opening balances and others are within the year, please explain.

B3-Staff-32
Exhibit B3 / Tab 4 / Schedule 1 / Tables 1-2

Question(s):

a) Please advise whether the capital in-service additions include capitalized borrowing costs (i.e. interest on Construction Work in Progress balances). If not, please explain. If so, please provide a breakdown of the capitalized borrowing costs for each year 2017-2026 and explain the methodology applied to calculate those borrowing costs.

Working Capital

B1-Staff-33
EB-2016-0152 / Exhibit B1 / Tab 1 / Schedule 1 / p. 1
Exhibit B1 / Tab 1 / Schedule 2 / p. 6

Preamble:

In its 2017-2021 Payment Amounts Proceeding, OPG stated that it continued to rely on its existing lead / lag methodology as the basis of the cash working capital given that: (1) the OEB accepted OPG's cash working capital calculation in the previous three hearings; (2) the amount of cash working capital remains very small relative to the overall size of rate base; (3) OPG's two main lead / lag day drivers (revenue from electricity generation and labour costs) are relatively stable; and (4) the OEB's existing filing guidelines[5] did not contemplate a new lead / lag study.

OPG stated that the passage of time since the original lead / lag study was conducted (2006) supported an updated assessment of the lead / lag days used to determine the cash working capital allowance.

Question(s):

a) Other than the passage of time since 2006, please detail the reasons / drivers warranting the need to update to the lead / lag days used to determine the cash working capital allowance. Please provide reasoning for the need to update with consideration to the reasoning provided in the 2017-2021 Payment Amounts Proceeding for not updating the lead / lag methodology.

[5] EB-2011-0286.

B1-Staff-34
Exhibit B1 / Tab 1 / Schedule 2 / p. 4

Preamble:

OPG retained Navigant Consulting Inc. (Navigant) to conduct a study on OPG's lead / lag days for cash working capital purposes. OPG stated that the types of costs Navigant determined should be included in the analysis are consistent with those in the previous lead / lag study, with the exception of interest on long-term debt.

Question(s):

a) Please explain why Navigant's inclusion of interest on long-term debt in the analysis is appropriate.

b) Please explain any other key differences or revised assumptions used in the lead / lag study conducted by Navigant when compared to the original lead / lag study conducted by OPG in 2006. Please indicate how / why such revisions are appropriate.

B1-Staff-35
Exhibit B1 / Tab 1 / Schedule 2 / pp. 2-3
Exhibit F2 / Tab 1 / Schedule 1 / p. 25

Preamble:

At the end of 2025, OPG plans that the shutdown of Pickering NGS will be completed. OPG calculated the cash working capital for the Generation Revenue component for the nuclear business to be $14.2 million. This value is proposed to be used for the Custom IR term.

Question(s):

a) Please explain the impact that accounting for the shutdown of Pickering NGS will have on the Generation Revenue component in 2025 and 2026, and ultimately, the cash working capital.

Exhibit C – Capitalization, Cost of Capital and Nuclear Liabilities

Exhibit C1 – Capitalization and Cost of Capital

C1-Staff-36

Exhibit C1 / Tab 1 / Schedule 2 / p. 5 / Chart 3
Exhibit C1 / Tab 1 / Schedule 2 / Table 10A and Table 12A

Preamble:

Chart 3 at Exhibit C1 / Tab 1 / Schedule 2 shows no forecasted debt issuances for 2024 to 2026. In Table 10A at C1 / Tab 1 / Schedule 2, OPG lists the debt of $400 million labelled as Issue 39 as having an Issue Date of 3/16/2024. Similarly, in Table 12A, OPG lists debt labelled Issue 29 as having an Issue Date of 11/22/2026.

Question(s):

a) In Table 10A, please confirm that 3/16/2024 is the Maturity Date, rather than the Issuance Date, of Issue 39 (i.e. that this debt, which seems to have been issued in 2020, is maturing on 3/16/2024).

b) In Table 12A, please confirm that 11/22/2026 is the Maturity Date, rather than the Issuance Date, of Issue 29 (i.e. that this debt, which seems to have been issued in 2016, is maturing on 11/22/2026).

C1-Staff-37

Exhibit C1 / Tab 1 / Schedule 3 / p. 1

Preamble:

OPG stated that it terminated its accounts receivable securitization program in November 2020.

Question(s):

a) Please provide further explanation regarding why OPG terminated its accounts securitization program, and how this has impacted OPG's short-term debt financing relative to its past practice.

C1-Staff-38
Exhibit C1 / Tab 1 / Schedule 3 / Table 2
EB-2016-0152 / Decision and Order, December 28, 2017 / p. 111 / Table 32

Preamble:

OEB staff has prepared the following table comparing the forecasts of OPG's short-term debt rate, as agreed upon in the partial settlement proposal in the 2017-2021 Payment Amounts Proceeding, relative to the actual (or expected actual) short-term interest rate for 2017 to 2021 as shown in Table 2 of Exhibit C1 / Tab 1 / Schedule 3. Also shown are the forecasts for the 2022 to 2026 period.

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Forecasted (EB-2016-0152)[6]	1.41%	2.73%	3.75%	3.80%	3.65%					
Actual[7]	0.79%	1.10%	1.67%	1.96%	0.70%					
Forecasted (EB-2020-0290)[7]						0.44%	0.47%	0.78%	1.16%	1.66%

Question(s):

a) Please confirm or correct the data shown in the table.

b) Has OPG reviewed its methodology for forecasting short-term interest rates as a result of comparing the forecasts to actuals for historical periods?

c) If yes to part (b), please indicate OPG's findings as a result of such a review. In particular, please describe any changes made to OPG's methodology as a result of any such review.

d) If OPG has not conducted any such reviews, please explain why not.

[6] EB-2016-0152 / Decision and Order / December 28, 2017 / p. 111 / Table 32.
[7] Exhibit C1 / Tab 1 / Schedule 3 / Table 2.

C1-Staff-39
Exhibit C1 / Tab 1 / Schedule 3 / p. 1
Exhibit C1 / Tab 1 / Schedule 3 / Table 2

Preamble:

OPG noted that its short-term debt is comprised of a commercial paper program backstopped by bank credit facilities. In November 2019, OPG established a second bank facility of USD $750 million. The US bank credit facility diversifies OPG's source of short-term funding beyond the existing $1 billion Canadian bank credit facility.

The cost of OPG's credit facilities is $5.2 million for each year of the Custom IR term as shown at Line 4 of Exhibit C1 / Tab 1 / Schedule 3 / Table 2. This compares to approximately $2.5 million for each year during the period 2016-2019 (prior to the establishment of the US credit facility).

Question(s):

a) Please explain why OPG determined that it was necessary to establish a second bank facility.

b) Please provide the breakdown of the bank facility costs between the US and Canadian credit facilities.

Concentric Report

Please note that references in this section to Concentric Energy Advisors' (Concentric) report (the Concentric Report) are to the page numbers of Concentric's evidence listed at the bottom of the page.

C1-Staff-40
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1

Question(s):

Please provide copies of the following documents referenced in the Concentric Report.

a) Scotiabank Equity Research Spotlight, Energy Infrastructure, March 18, 2019, referenced at page 20, footnote 30.

b) Moody's Investors Service, Proposed Refinements to the Regulated Utilities Rating Methodology and Our Evolving View of US Utility Regulation, September 23, 2013, referenced at page 21, footnote 31.

c) Moody's Investors Service, Rating Methodology: Regulated Electric and Gas Utilities, June 23, 2017, referenced at page 35, footnote 40.

d) S&P Global Ratings, Research Update: SNC-Lavalin Group Inc. 'BB+' Ratings Affirmed; Outlook Remains Negative On Slower-Than-Expected Deleveraging, May 2020, referenced at page 39, footnote 48.

e) OPG, Quarterly Risk Report – Q2 FY2020, August 11, 2020, referenced at page 48, footnote 69.

f) McKinsey and Company, Why, and how, utilities should start to manage climate change risk, April 2019, referenced at page 50, footnote 82.

C1-Staff-41
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 33
Exhibit A2 / Tab 3 / Schedule 1 / Attachment 6 / p. 5

On page 33 of the Concentric Report, Concentric stated:

> OPG's hydroelectric base payment amounts are legislatively set at the 2021 amount and as such will not increase over the 2022-2026 period. As a result, OPG will be exposed to a level of incremental inflationary risk over the upcoming period, relative to a hydroelectric payment amount set under a price-cap incentive regulation model applied in EB-2016-0152.
>
> Based on the above, Concentric concludes that although some incremental risks have emerged, OPG's operational risks and regulatory risks related to its prescribed hydroelectric facilities have not changed significantly since EB-2016-0152, other than additional risks from rising threat of climate driven impacts (discussed further below [later in the report]) and incremental inflationary risk.

On page 5 of Exhibit A2 / Tab 3 / Schedule 1 / Attachment 6, Moody's Investor Services (Moody's) stated:

> On November 10, 2020, the Province took steps to establish the hydroelectric base regulated price for the period 2021-2026 at the 2021 based regulated price. While this provides price certainty for the period, it may be challenging for OPG to earn its allowed returns over the period given ongoing investments in rate base assets during the period that exceed depreciation.

Question(s):

a) Please provide quantitative estimates of the additional "operational risks and regulatory risks related to [OPG's] prescribed hydroelectric facilities" for each of:

   i. Climate change

   ii. Incremental inflationary risk due to the Hydroelectric payment price freeze from 2021 to 2026

   If this is not possible, please explain.

C1-Staff-42
Exhibit C1 / Tab 1 / Attachment 1 / p. 3
Régie de l'énergie / Décision D-2003-93 R-3492-2002 / May 21, 2003[8]
Régie de l'énergie / Decision D-2014-034 R-3842-2013 / March 4, 2014[9]
Authorized Return on Equity for Canadian and U.S. Gas and Electric Utilities, Volume V, May 25, 2017 (revised)[10]

Preamble:

On page 3 of the Concentric Report, Concentric stated:

> Applied to the OEB's framework for determining the cost of capital, the decline in the government bond yields is reflected in a decrease in allowed ROE from 8.52% for the 2020 year to 8.34% for the 2021 year, per the OEB's most recent update to the cost of capital parameters. *This will place the allowed ROE in Ontario below that of any other North American regulatory jurisdiction*, at a time when market views of utility risk appear to be increasing. For OPG specifically, the reduction in the allowed ROE will negatively affect OPG's credit metrics at a time when they are already expected to be pressured. *[Emphasis added]*

OEB staff notes that Concentric has periodically issued short reports summarizing the allowed ROEs for utilities in Canadian jurisdictions and comparing them also against the allowed ROEs for U.S. utilities. The most recent report available on Concentric's website is Authorized Return on Equity for Canadian and U.S. Gas and Electric Utilities, Volume V, May 25, 2017 (revised). On page 4 of this report, Concentric documents an ROE of 8.20% for Hydro-Québec TransÉnergie for every year from 2015 to 2017, and with a deemed equity thickness of 30%.

[8] Régie de l'énergie / Décision D-2003-93 R-3492-2002, 21 mai 2003.
[9] Régie de l'énergie / Decision D-2014-034 R-3842-2013, 4 mars 2014.
[10] This document is attached as Appendix A to OEB staff's interrogatories.

OEB staff understands that Hydro-Québec (Distribution) has a deemed equity thickness of 35% and Hydro-Québec (Transmission) has a deemed equity thickness of 30%, with both deemed equity thicknesses determined in a 2003 Régie de l'énergie Décision. The allowed ROE of 8.20% was set in early 2014 based on a decision of the Régie de l'énergie. OEB staff understands that the allowed ROE for Hydro-Québec has not been changed since.

Question(s):

a) If Concentric has prepared an updated report on allowed ROEs for Canadian and U.S. utilities since the May 25, 2017 report, please file a copy.

b) Please confirm or correct OEB staff's understanding that Hydro-Québec's allowed ROE continues to be 8.20%.

C1-Staff-43
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1
Exhibit A2 / Tab 2 / Schedule 1

Preamble:

On page 2 of Exhibit A2 / Tab 2 / Schedule 1, OPG stated that the 2020-2026 Business Plan covers a range of important events and initiatives for OPG's regulated generating facilities, including:

- Successfully executing the DRP and positioning the Darlington NGS for strong post-refurbishment performance

- Optimizing the remaining operating life of Pickering NGS in a safe, reliable, and economically effective manner

- Achieving a post-Pickering cost structure that mitigates, to a significant extent, the diseconomies of scale that will result within OPG from the Pickering NGS shutdown

- Where possible, minimizing the impact of transitioning the workforce to a post-Pickering organization, with an expected reduction of over 3,000 employees following the station's shutdown

- Investing in continued reliability, resilience and value of the regulated hydroelectric fleet

In its evidence, Concentric points to risks that OPG faces during the term plan, particularly towards the end of the plan term in 2025 and 2026, in support of its proposed 50% equity thickness. Specifically, Concentric stated, on page 1 of the Concentric Report:

> In our analysis, OPG's risk profile will increase materially during the 2022 to 2026 period, as compared to its risk profile at the time of EB-2016-0152. The most significant risk factors contributing to the increase are: the Darlington Refurbishment Project ("DRP") entering a critical stage of execution; the continued operation of aging nuclear units; the retirement of the Pickering nuclear station; the continued shift of OPG's rate base to reflect a greater portion of nuclear assets, combined with an increase in the financial value of each unit of nuclear output; and increasing climate change impacts.

Question(s):

a) Can Concentric provide a quantitative assessment of the importance of each of the factors it cited as reasons for its assessment of increasing risk in the quoted paragraph above? At a minimum, can Concentric provide a ranking of the importance of each of these factors in Concentric's assessment of increased regulatory risk for OPG during 2022-2026? If not, please explain.

b) On page 16 of Exhibit A2 / Tab 2 / Schedule 1, OPG stated that OPG does not seek recovery of costs arising from any Pickering NGS closure activities in this application and will record them in the Pickering Closure Cost Deferral Account pursuant to O. Reg. 53/05.

    i. Please identify whether, and if so, how, the availability for the recording of certain costs in the Pickering Closure Cost Deferral Account has been taken into account in Concentric's analysis of OPG's business risk and the commensurate equity thickness.

    ii. Can Concentric provide examples of analogous DVAs for asset decommissioning or retirement costs in the comparator utilities used in its analysis? If so, please identify such analogous examples.

C1-Staff-44
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 4
Exhibit A1 / Tab 4 / Schedule 2 / pp. 2-3 / Chart 1
Exhibit A1 / Tab 4 / Schedule 3 / p. 2 / Chart 1

Preamble:

On page 4 of the Concentric Report, Concentric stated:

> In addition to the increased generation risk leading up to the end of the station's commercial operations, the shutdown and retirement of Pickering, comprising 60% of the company's operating nuclear reactors and served by thousands of employees, in the upcoming rate period presents new and unique challenges for OPG related to significant disruptive organizational changes that can impact operational performance, increase forecast risk and reduce the diversification of OPG's nuclear fleet.

Chart 1 at Exhibit A1 / Tab 4 / Schedule 3 provides a summary of the capacity of the NGSs and units.

Chart 1 at Exhibit A1 / Tab 4 / Schedule 2 provides a summary of the capacity of the prescribed hydroelectric generating stations.

Question(s):

a) Please confirm that 60% refers to the number of nuclear generating units (6 in operation at Pickering NGS, 4 at Darlington NGS) and not to the generation capacity split between Pickering NGS and Darlington NGS.

b) Please confirm that, with the shutdown of Pickering NGS, the reduction in OPG's nuclear generation capacity, assuming all Darlington NGS units are available, would be to 3,512 MW of the current 6,606 MW, a reduction of approximately 47%.

c) OEB staff notes that not all of the hydroelectric generating capacity would be considered baseload, but the Saunders plant, most of the Niagara G.S., and certain other hydroelectric stations would function as baseload. However, please confirm that the generating capacity of OPG's prescribed hydroelectric generation assets, per Chart 1 at Exhibit A1 / Tab 4 / Schedule 2, is 6,423 MW.

d) Please confirm that OPG's regulated generation capacity is currently 6,423 MW + 6,606 MW = 13,029 MW, and that it will be 6,423 MW + 3,512 MW = 9,935 MW with the shutdown of Pickering NGS. Therefore, please confirm that the reduction in OPG’s regulated generation capacity with the Pickering NGS shutdown after 2025 would be 23.75%.

e) During most of the 2017-2021 period, Unit 2 of the Darlington NGS was shut down for refurbishment, coming back into service in early 2020. Therefore, OPG’s nuclear generation capacity during most of the current term was reduced by 934 MW from the overall capacity of 6,606 MW. OEB staff also notes that Pickering NGS’s operational life has been extended, and that approval for Pickering Extended Operations was still being considered by the Canadian Nuclear Safety Commission (CNSC) at the time of OPG’s 2017-2021 Payment Amounts Proceeding.

   i. Was there not a similar increased business risk at the time of the OPG’s 2017-2021 Payment Amounts Proceeding that would have resulted from the loss of regulated nuclear generation capacity and of concentration of nuclear generation at Darlington NGS if Pickering Extended Operations was not approved by the CNSC?

   ii. Can Concentric substantiate, quantitatively if possible, what is the increased risk due to the inevitable shutdown of Pickering NGS during (and later in) the 2022-2026 plan period relative to the business risk of a potential shutdown that could have occurred during the 2017-2021 plan period absent CNSC approval?

C1-Staff-45
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1
EB-2016-0152 / Exhibit C1 / Tab 1 / Attachment 1
EB-2016-0152 / Decision and Order / December 28, 2017

Preamble:

In OPG’s 2017-2021 Payment Amounts Proceeding, Concentric also filed similar evidence regarding the appropriate deemed capital structure for the 2017-2021 term. Concentric’s evidence was also filed as Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 in that proceeding, and was titled Common Equity Ratio: For OPG’s Regulated Generation.

OEB staff notes that, in OPG’s 2017-2021 Payment Amounts Proceeding, Concentric relied on the increase in the proportion of OPG’s regulated rate base that represented nuclear generation by the end of the 2017-2021 term as one key factor in its assessment of OPG's increased business risk in that plan term.[11] OEB staff notes that Concentric similarly relied on the proportions of OPG's regulated rate base accounted by nuclear generation, which increases over the 2022-2026 plan term as refurbished units at Darlington NGS re-enter service, as a major factor for its proposed equity thickness of 50%.[12]

Question(s):

a) Please identify any substantive changes in Concentric's approach or methodology used for preparing its report filed with this application compared with its evidence filed in OPG's 2017-2021 Payment Amounts Proceeding.

C1-Staff-46

Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 4-5

Preamble:

On page 4 of the Concentric Report, Concentric stated:

> OPG's regulated asset mix will continue to shift towards a higher proportion of nuclear assets, which, as the OEB previously found, are riskier than the hydroelectric business. Upon completion of the DRP in 2026, nuclear generation operations are projected to comprise approximately 60% of OPG's overall regulated rate base, compared to 32% as of December 31, 2019.

Question(s):

a) In Figure 1 at Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 5, are the percentages shown for the percentage of OPG's regulated rate base composed of nuclear assets at December 31 or average annual / mid-year figures?

C1-Staff-47

Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 23

Preamble:

On page 23 of the Concentric Report, with respect to country risk, Concentric stated:

[11] EB-2016-0152 / Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / May 2016 / p. 2.
[12] Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 7.

> They [equity and credit analysts] tend to consider country risk as a factor in their investment analysis when they are comparing Canada and the U.S. to other countries outside North America, in particular emerging markets.

Question(s):

a) How do the deemed equity thickness and allowed equity returns in Ontario compare with those applied to regulated electricity sector assets in jurisdictions other than the U.S., such as Australia and the United Kingdom?

C1-Staff-48
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 26

Question(s):

a) Please provide an update to Figure 4 at Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 26 by adding a column to the left of the "Source", and showing results for the full calendar year 2020.

C1-Staff-49
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 23-24

Preamble:

On pages 23-24 of the Concentric Report, Concentric discussed "influence of regulatory risk on investment analysis."

Question(s):

a) For companies that include a mix of regulated and unregulated assets, would Concentric characterize the unregulated assets as being more or less risky than the regulated assets? Please explain your response with reasons.

<u>C1-Staff-50</u>
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 3, 27-28

Preamble:

On page 3 of the Concentric Report, Concentric stated:

> Utility betas, which measure the movement of individual stock prices in relation to the overall market, are well above their historical norms, and market indicators signal that the cost of equity for utilities has increased during the pandemic.

On page 27 of the Concentric Report, Concentric stated:

> Looking at utilities specifically, Figure 6 below illustrates a significant upshift in the betas for utility stocks over the past twelve months, centered in the March/April 2020 timeframe. Beta is broadly considered a measure of risk, and this upward shift in utility betas signals that investors are not considering utilities at the same low levels of relative risk as they have in the past. In the context of the current pandemic, we believe this is likely driven, at least in part, by an uncertain economic outlook and a recognition that even regulated utilities face increased risk exposure in the current and foreseeable environment.

Concentric provided Figure 6 at Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 28 and identified the utility betas as being sourced from Bloomberg.

Question(s):

a) With reference to the quote from page 3 of the Concentric Report, please describe what is meant by “historical norms” and how current observations differ.

b) Does Concentric consider that this departure from historical norms to be temporary (i.e. related to the COVID-19 pandemic) or permanent. Please provide the reasoning.

c) Please provide the data that Concentric has relied upon to produce Figure 6 at Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 28. In the alternative, please provide exact references to the data series used from Bloomberg for the production of Figure 6.

C1-Staff-51
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 28

Preamble:

On page 28 of the Concentric Report, Concentric stated:

> The above trend [referring to Figure 6] is unlike prior periods of market disruption where utilities have typically served as a safe haven for investors. It appears that the pandemic has left investors uncertain of the outlook for the sector amid concerns for slumping demand and disruption to business plans, with utility betas in both the U.S. and Canada increasing substantially since January 2020. This indicates that the cost of equity for regulated utilities has increased.

Question(s):

a) Concentric indicates that because betas have increased, the cost of equity has increased. Based on the capital asset pricing model ("CAPM"), is it possible for the overall cost of equity to fall even if betas rise, provided the risk-free rate falls?

b) Does the OEB update the cost of capital more frequently than do regulators in U.S. jurisdictions? If so, does this mean that future allowed equity costs in the U.S. may fall if risk-free rates remain low?

c) If interest rates begin to rise, does Ontario's system of regular adjustments to the cost of equity provide a risk mitigant for regulated entities relative to what is the norm in many other Canadian and U.S. jurisdictions?

C1-Staff-52
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1
EB-2016-0152 / Exhibit C1 / Tab 1 / Attachment 1

Preamble:

On page 30 of its evidence filed in OPG's 2017-2021 Payment Amounts Proceeding, Concentric stated the following with respect to its selection of the comparator group for assessing OPG's appropriate capital structure:

> As a starting point for our screening process, Concentric reviewed data related to both Canadian and U.S. utilities, including the following Canadian utilities: Canadian Utilities Limited, Emera Inc. ("Emera"), Enbridge Inc., Fortis Inc. ("Fortis"), and TransCanada Corporation, and the 46 U.S. companies that Value Line classifies as "Electric Utilities".

On page 31 of that evidence, Concentric noted that it reduced the comparator group to 10 U.S. utilities and two Canadian utilities in addition to OPG. On page 32, Concentric provided Figure 5 listing the utilities in the selected comparator group, along with Credit Rating Agency summary ratings.

On page 63 of the Concentric Report filed in the current proceeding, Concentric stated:

> As a starting point for our screening process for the Concentric Proxy Group, Concentric reviewed data related to both Canadian and U.S. utilities, including the following Canadian utilities: Algonquin Power & Utilities Corp ("Algonquin"), Canadian Utilities Limited, Emera Inc. ("Emera"), Enbridge Inc., Fortis Inc. ("Fortis"), and TC Energy Corporation, and the 37 U.S. companies that Value Line classifies as "Electric Utilities."

Following on pages 65-66, Concentric noted that no other Canadian utility met all of Concentric's selection criteria. However, Concentric included three Canadian utilities (Algonquin, Emera and Fortis) who each met most of the criteria. On page 67, Concentric provided Figure 16, which shows the three Canadian utilities and 16 U.S. utilities that Concentric included in its proxy group.

OEB staff has prepared the following table comparing the selected utilities in Concentric's comparator groups in the studies in OPG's 2017-2021 Payment Amounts Proceeding and 2022-2026 Payment Amounts application.

Utility Name	Included in Comparator Sample	
	EB-2016-0152	**EB-2020-0290**
Ontario Power Generation Inc.	Yes	Yes
ALETTE Inc.	Yes	Yes
Algonquin Power and Utilities Corp.		Yes
Ameren Corporation	Yes	Yes
American Electric Power Company Inc.	Yes	Yes
Avista Corporation		Yes
Duke Energy Corporation	Yes	Yes
Edison International	Yes	Yes
El Paso Electric Company	Yes	Yes
Emera Inc.	Yes	Yes
Entergy Corporation	Yes	Yes
Evergy Inc.		Yes
Exelon Corporation		Yes
FirstEnergy Corporation	Yes	Yes
Fortis Inc.	Yes	Yes
Great Plains Energy Inc.	Yes	
IDACORP Inc.	Yes	Yes
NextEra Energy Inc.	Yes	Yes
PG&E Corporation	Yes	
Pinnacle West Capital Corporation	Yes	Yes
PNM Resources Inc.	Yes	Yes
Portland General Electric Company	Yes	Yes
Public Service Enterprise Group, Inc.		Yes
Southern Company	Yes	Yes
Westar Energy Inc.	Yes	
Xcel Energy Inc.	Yes	

Question(s):

a) Please confirm or correct the data shown in the table above.

b) Please explain the reasons for each utility added to, or removed from, the comparator group from OPG’s 2017-2021 Payment Amounts Proceeding to the current application.

c) Other than what Concentric has documented in the two studies, are there any other changes that Concentric has made in the selection criteria for determining the comparator groups in the two studies?

C1-Staff-53

Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 34, 42, 71

Preamble:

On page 34 the Concentric Report, Concentric stated:

> Under the current rate plan, OPG recovers the cost of its nuclear facilities under a custom incentive rate-setting ("Custom IR") framework established in EB-2016-0152. Under the Custom IR framework, OPG continues to be at risk related to the variability in the generating output of its nuclear facilities. OPG's risk related to the variability in nuclear generating output compounds its nuclear-specific business risks, as discussed herein, and also distinguishes OPG from other regulated North American generators.

On page 42 of the Concentric Report, Concentric provided a brief summary of examples from Florida, South Carolina and Georgia.

On page 71 of the Concentric Report, Concentric stated:

> The companies in the proxy group do not face comparable risk, and, in fact, many recover costs through a mix of fixed and variable charges, and/or have decoupling in place. For the proxy companies, revenue decoupling mechanisms further reduce exposure to volumetric risk.

Question(s):

a) Is Concentric aware of any other North American utilities being charged for replacement power and / or other added costs when outages were longer than expected, or plants underperformed?

b) Please discuss treatment of costs associated with the accelerated retirement of the Crystal River Nuclear Plant in Florida. What proportion of costs were assumed by shareholders?

C1-Staff-54

OPG's Green Bond Impact Report 2020[13]

Preamble:

On page 1 of OPG's 2020 Green Bond Impact Report, OPG stated:

[13] https://www.opg.com/investor-relations/green-bonds/

> In Q2, on April 8, 2020, OPG issued a third and fourth green bond offering under its Medium Term Note Program. The issuance, totaling $1.2 billion, consisted of $400 million of senior notes maturing in April 2025 with a coupon interest rate of 2.89 percent and $800 million of senior notes maturing in April 2030 with a coupon interest rate of 3.22 percent.

Question(s):

a) Please describe OPG's experience in the issuance of Green Bonds. How does the cost of funds associated with the issuance of Green Bonds differ from the cost of funds issued without the Green Bond designation?

b) In Concentric's view, how does a firm's ability to issue Green Bonds affect the firm's cost of capital.

c) Has OPG's issuance of Green Bonds been factored into Concentric's analysis of its recommended equity thickness? Please explain your response.

C1-Staff-55

Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 50

Preamble:

On page 50 of the Concentric Report, Concentric stated:

> S&P has incorporated ESG criteria into its credit rating analysis, while other investment firms and pension funds have adopted restrictions that prohibit them from owning equity or debt in companies seen as contributing to climate change. For example, in January 2020, investment manager BlackRock sent a letter to its clients announcing a number of initiatives to place sustainability at the center of its investment approach, including: making sustainability integral to portfolio management; exiting investments that present a high sustainability-related risk, and strengthening its commitment to sustainability and transparency in investment stewardship activities.

Question(s):

a) Does the emergence of environmental, social and governance criteria benefit OPG by increasing the relative attractiveness of lending to its zero-carbon emissions regulated asset portfolio?

C1-Staff-56
Exhibit C1 / Tab 1/ Schedule 1 / Attachment 1 / p. 11

Preamble:

On page 11 of the Concentric Report, Concentric stated:

> The OEB [in EB-2007-0905] determined that a 47% equity ratio was appropriate for OPG, finding that OPG was of higher risk than any other Ontario energy utility but of lower risk than merchant generators.

Question(s):

a) In typical Canadian project finance transactions related to zero emitting resources with long term power purchase agreements (PPAs), what level of equity thickness is normally required to obtain financing?

b) How would Concentric compare the level of risk associated with a long term PPA between a zero emitting resource and a Canadian provincially backed offtaker with the level of risk that OPG faces in its regulatory arrangements with the OEB?

C1-Staff-57
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 73

Preamble:

On page 73 of the Concentric Report, Concentric stated:

> Book equity ratios at the holding company level, however, reflect a different risk profile than pure regulated utility operations, and Concentric has applied less weight to those results.

Question(s):

a) If a holding company's unregulated assets are at least as risky as its regulated assets, but the holding company equity ratio is less than the authorized equity ratio, does that imply that the capital markets would be comfortable with a lower authorized equity ratio? Please explain with reasons.

C1-Staff-58
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 30, 35

Preamble:

On page 30 of the Concentric Report, Concentric stated:

> … OPG is entering a period of acute risk beyond what it has experienced historically, with three units coming offline in the upcoming rate setting period with overlapping outages, new FOAK [first of a kind] scope being added to the refurbishment, competition for resources with the Bruce Power refurbishment, and ongoing constraints and risks presented by the COVID-19 pandemic.

On page 35 of the Concentric Report, Concentric stated:

> …we note that recent events in the nuclear construction business since EB-2016-0152 have further raised the perceived risk of large nuclear facility projects among investors and credit rating agencies. In particular, two new nuclear projects in the U.S. (i.e., the Vogtle Plant in Georgia and the now-cancelled Summer Plant in South Carolina), both of which were being pursued under favorable legislative and regulatory frameworks, have run into cost and schedule issues.

Question(s):

a) Upon completion, what is the total expected cost of the additional two units at Southern Co.'s Vogtle site?

b) Are the differences in execution risk (i.e. cost, scope and timing) in OPG's current nuclear refurbishment program from prior such programs as large as the differences between the construction of new Westinghouse AP1000 units and maintenance of the existing units at Southern Co.'s Vogtle site in Georgia?

C1-Staff-59
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 38

Preamble:

On page 38 of the Concentric Report, Concentric stated:

> Second, OPG plans to execute new scope during the refurbishment of Units 3, 1 and 4 in the form of digital turbine controls and generator excitation controls. This scope was excluded from the Unit 2 refurbishment for two main reasons: (1) there was still useful life left in the existing control systems on Unit 2; and (2) to mitigate risk, given that Unit 2 was the first unit to be refurbished and that this large FOAK modification would have introduced

> additional risk into the planning and execution of the refurbishment. The addition of this scope with which OPG does not yet have experience brings with it increased challenges and risks for the remaining units.

Question(s):

a) Concentric focused on digital turbine controls and generator excitation controls as being among the new technologies to be deployed during OPG's current refurbishment program. Are either of these technologies unique to nuclear power plants?

b) Has OPG installed digital controls at any of its hydroelectric generating stations? If yes, how did actual budget and schedule compare with the planned budget and schedule for such installations, and has the performance of the digital controls met expectations prior to installation?

C1-Staff-60
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 39-40

Preamble:

On pages 39-40 of the Concentric Report, Concentric discussed the current COVID-19 pandemic, and its impact as a "black swan event" on OPG's operations. On page 40 of the Concentric Report, Concentric stated:

> Depending on the course of the COVID-19 pandemic, these factors [productivity risk and resource availability risk] may have an impact on the ultimate cost and schedule of the DRP.

Question(s):

a) Why does Concentric believe that the COVID-19 pandemic is a risk for the 2022-2026 period, as opposed to a temporary risk ending by December 31, 2021?

C1-Staff-61
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 46-47

Preamble:

On pages 46-47 of the Concentric Report, Concentric discussed its views regarding the impact of the Pickering NGS retirement and associated transformation of its workforce and operations on OPG's ability to forecast and plan for operations, particularly beginning in 2025 and 2026. On page 46 of the Concentric Report, Concentric stated:

> Namely, for at least the years 2025 and 2026, OPG must forecast its operating profile as a very different organization, without the benefit of historical experience.

Question(s):

a) Are Concentric's comments solely related to nuclear generation, or do they extend to regulated hydroelectric generation as well?

b) Please confirm that OPG undertook a multi-year business transformation initiative that was reviewed in the 2014-2015 Payment Amounts Proceeding.[14]

c) Does Concentric agree that OPG's historical experience with corporate business transformation should enhance OPG's ability to forecast its operations even factoring in the retirement of Pickering NGS? Please explain your response.

C1-Staff-62

Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 46

Preamble:

On page 46 of the Concentric Report, Concentric stated:

> Organizationally, the end of Pickering commercial operations will require OPG to downsize 3,000-plus employees, which will be a complex undertaking. The inevitable disruption that will be caused by the large scale reorganization carries risks to the operational effectiveness and efficiency of the Company's nuclear business through the upcoming rate term.

Question(s):

a) If an appropriate number of existing staff are allocated to the remaining facilities, and focused on those facilities, how will downsizing pose an adverse risk on operational effectiveness and efficiency for OPG?

[14] EB-2013-0321.

C1-Staff-63
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / pp. 48-49

Preamble:

On page 48 the Concentric Report, Concentric stated:

> OPG's Calabogie Hydroelectric Generating Station, a five MW regulated facility that OPG had been planning to rebuild, was struck and largely destroyed by a tornado in September 2018.
>
> A recent report released by Ottawa predicts more intense precipitation, increased risk of tornadoes and wildfires in the Ottawa area due to climate change.

On page 49 of the Concentric Report, Concentric further stated:

> Scientists have also expressed high confidence that streamflow regimes will shift and that daily extreme precipitation will increase in Canada.

Question(s):

a) How is the risk of more intense precipitation referred to likely to impact production at OPG's hydroelectric generating facilities over the 2022-2026 period?

b) To date, what evidence is there of increased forest fire activity in Ontario, and how have forest fires impacted OPG's generating stations? Please identify what forest fires have impacted OPG's generating stations, the station(s) impacted, and the date(s) of each occurrence.

c) Did Concentric consider the potential availability of Z-factor treatment in its assessment of OPG's risk profile with respect to climate change-related events.

C1-Staff-64
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / page 59

Preamble:

On page 59 of the Concentric Report, Concentric stated:

> These core ratios are expected to be under pressure during the earlier years of the upcoming rate period and OPG's business plan forecasts one or both of them will temporarily decline below the corresponding thresholds.

Question(s):

a) In Concentric's view, would a temporary decline in one of the measures likely result in a downgrade of OPG's credit rating as assessed by the credit rating agencies?

b) How big of a decline in the core ratios would Concentric view as being necessary to cause a downgrade?

C1-Staff-65
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 65

Preamble:

On page 65 of the Concentric Report, Concentric stated:

> In order to broaden the proxy group to include at least a minimal number of Canadian utilities, Concentric included Emera, Fortis, and Algonquin in the proxy group, as they otherwise meet our screening criteria.

Question(s):

a) What proportion of the assets of each of these Canadian entities is outside of Canada? Of the assets that are outside of Canada, what proportion is in the U.S.? Please provide the same breakdown for revenues and profits for each of these Canadian entities.

C1-Staff-66
Exhibit 3 / Tab 1 / Schedule 1 / Attachment 1 / pp. 69-71

Preamble:

On pages 69-71 of the Concentric Report, Concentric provided an analysis of what it considers the main DVAs related to OPG's regulated nuclear operations. It provides a list and description of these accounts.

Question(s):

a) Please confirm that Concentric's recommended equity thickness for OPG's regulated operations on a stand-alone basis pertains to the combination of prescribed (i.e. regulated) nuclear and hydroelectric generation assets and operations. If not, please explain.

b) Please explain why Concentric did not also consider the DVAs related to regulated hydroelectric operations in its analysis.

C1-Staff-67

Exhibit 3 / Tab 1 / Schedule 1 / Attachment 1 / pp. 71-72

Preamble:

On pages 71-72 of the Concentric Report, Concentric stated:

> In addition to proxy group comparability, Concentric also considered the general comparability of OPG's deferral and variance accounts to other regulated electric utilities in Ontario. In doing so, Concentric observed that the majority of OPG's accounts would be classified as "Group 2" accounts according to the OEB's Accounting Procedures Handbook. Group 2 accounts require a prudence review by the OEB before the utility is allowed to recover those costs. In contrast, Group 1 deferral and variance accounts do not require a prudence review.
>
> Concentric reviewed the deferral and variance accounts for a sample of other regulated electric utilities in Ontario (including Hydro One Networks, Toronto Hydro, Hydro Ottawa, Niagara-on-the-Lake Hydro, and ENWIN) and determined that those companies have a mix of Group 1 and Group 2 accounts. Because the disposition of Group 2 deferral and variance accounts involves a greater degree of regulatory scrutiny than Group 1 accounts, Concentric concludes that OPG has relatively greater risk of cost recovery for its deferral and variance accounts than do other electric utilities in Ontario.

Question(s):

a) Given that OPG, as an electricity generator, is at the front end of the supply chain from producer to end consumer, please identify what costs, and what associated DVAs, OPG has that are analogous to the Group 1 DVAs of Ontario electricity distributors.

b) Please explain the analysis that Concentric used. Was its analysis based on a count of the DVAs, or did it consider the quantum of revenues recorded in Group 1 versus Group 2 accounts?

c) Did Concentric take into account the magnitude of DVA balances relative to the revenue requirement of the firm (i.e. taking into account the scrutiny, regulatory lag and risk of denial of recovery of DVA balances on cash flow and various credit metrics of OPG relative to Ontario electricity distributors)? Did Concentric take into account the timing of dispositions and recovery of DVA balances, between Group 1 versus Group 2 accounts, and also in comparing OPG's DVAs versus those for Ontario electricity distributors? Please explain your response.

d) Did Concentric come to its conclusion that "OPG has relatively greater risk of cost recovery for its deferral and variance accounts than do other electric utilities in Ontario" solely on its qualitative judgement that: "[b]ecause the disposition of Group 2 deferral and variance accounts involves a greater degree of regulatory scrutiny than Group 1 accounts"? If there were other quantitative or qualitative considerations used by Concentric in reaching its conclusion, please provide an explanation, and any necessary data used by Concentric in reaching its conclusion.

C1-Staff-68

Exhibit 3 / Tab 1 / Schedule 1 / Attachment 1 / pp. 72-73 / Figures 19-20
Exhibit 3 / Tab 1 / Schedule 1 / Attachment 1 / Exhibit 1

Question(s):

a) Please identify the source of the data shown in Figure 19.

b) Please confirm that Figure 20 is derived from the data contained in Exhibit 1 of Concentric's report. If not, please explain and provide the data used.

c) Please confirm that, in Figure 20, for each utility, the white space above the bar of % Hydro Production (shaded) and/or % Nuclear Production (solid) represents generation owned and operated by each utility and powered by other fuel sources (coal, natural gas, biomass, multi-fuel, wind, solar).

d) Please confirm whether all of the utility generation represented by the white space above the bar is regulated, unregulated, or a mix of regulated and unregulated generation.

e) If the white space includes unregulated generation for other comparator utilities, please explain why Concentric showed only the regulated portion of OPG's generation portfolio in Figure 20.

f) Please provide an updated version of Figure 20, and a table in Excel format showing the data, presenting the percentage of generation by fuel type (e.g. hydroelectric, coal, steam, wind, solar, biomass, gas) and distinguishing between regulated and unregulated generation for OPG and all comparator utilities (i.e. a 100% bar chart).

C1-Staff-69
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 63
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / Exhibit 2.2

Preamble:

On page 63 of the Concentric Report, Concentric noted that it considered that ownership of generation assets included in rate base was one factor for inclusion of a holding company in the proxy group.

The only two operating companies listed in Exhibit 2.2 of the Concentric Report that are described as being vertically integrated, and thus having electricity generation are Florida Power and Light Co. and Gulf Power Co., both subsidiaries of NextEra Energy Co. For both Florida Power and Light Co. and Gulf Power Co., the authorized equity thickness is shown as N/A. In calculating the average equity thickness at the holding company level, it appears that N/A values are excluded.

Question(s):

a) Please confirm that NextEra Energy Co.'s equity thickness is based solely on the authorized equity thickness for Pivotal Utility Holdings Inc., a natural gas distributor.

b) Please confirm that the analysis of equity thickness (and hence also of debt thickness) for the Moody's proxy group is based solely on natural gas and electricity distribution utilities (i.e. there is no generation reflected in the equity thickness numbers calculated for the Moody's proxy group).

C1-Staff-70
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 1

Preamble:

Concentric noted that the OEB adjusts for changes in risk through changes in the equity thickness. In other jurisdictions, differences in relative risk between firms or sectors are accounted for through allowing different ROEs.

OEB staff notes that the differences in risk can be accounted for through adjusting either the ROE and / or the equity thickness, in order to satisfy the Fair Return Standard. However, it is often more practical to alter either the ROE or the equity thickness as opposed to varying both parameters.

OEB staff notes that Concentric's analysis considers solely the authorized and actual equity thickness (and similarly the authorized and actual debt thickness) of OPG and of the holding and operating companies in the two proxy groups. There is no data or analysis provided on the allowed or achieved ROEs of the firms in the comparator groups.

Question(s):

a) Does Concentric agree that, for two firms of comparable risk, the Fair Return Standard may be satisfied even if the allowed equity thicknesses are different, so long as the allowed ROEs are offsetting?

b) Please explain why Concentric has not considered differences in allowed and achieved ROEs for the firms in the proxy groups in order to ascertain that these firms are "similar enough" to each other and to OPG.

c) If Concentric has conducted analysis on the allowed and achieved ROEs for the holding and operating companies in its proxy groups, please provide the analysis and all pertinent data. Please provide the data in working Microsoft Excel format, where possible.

C1-Staff-71
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / p. 1

Preamble:

On page 1 of the Concentric Report, Concentric stated:

> Our recommended equity ratio for OPG in the upcoming rate setting period is set at a level that balances the results of our analysis, which indicates heightened risk for OPG on an absolute basis…

Question(s):

a) Concentric refers to "heightened risk for OPG". How does Concentric define "risk … on an absolute basis" as used above?

C1-Staff-72
Exhibit C1 / Tab 1 / Attachment 1 / p. 3

Preamble:

On page 3 of the Concentric Report, Concentric stated:

> For OPG specifically, the reduction in the allowed ROE will negatively affect OPG's credit metrics at a time when they are already expected to be pressured.

Question(s):

a) Has OPG or Concentric performed financial modeling for the 2022-2026 period using various levels of equity thickness?

b) If yes, please provide the results of the modelling, summarizing assumptions made, and showing the specific impact on credit metrics of each scenario tested. Which credit metrics were most affected, and what are the potential implications on OPG's financial and operational health?

c) How do the results of the scenarios compare to OPG's credit metrics for the 2017-2021 period?

C1-Staff-73
Exhibit C1 / Tab 1 / Schedule 1 / Attachment 1 / Exhibits 1.1-5.1

Question(s):

a) Please provide all of the Exhibits 1.1 to 5.1 in Microsoft Excel format, if available.

Exhibit C2 – Nuclear Liabilities

C2-Staff-74
Exhibit C2 / Tab 1 / Schedule 1 / p. 5

Preamble:

OPG stated that as a result of the Saugeen Ojibway Nation (SON) vote to not support the proposed permanent emplacement of low and intermediate level waste (L&ILW) into a separate deep geologic repository adjacent to the Western Waste Management Facility, OPG is exploring alternative solutions for the safe long-term management of

L&ILW. Due to significant inherent uncertainties associated with potential alternative solutions, no adjustments to OPG's estimate of nuclear liabilities have been made as a result of the vote, in accordance with US GAAP and the ONFA.

Question(s):

a) Please discuss the materiality and potential magnitude of an adjustment to nuclear liabilities resulting from the SON vote, despite the inherent uncertainties associated with alternatives.

b) Please indicate when OPG expects to decide upon a solution for the safe, long-term management of L&ILW referenced above.

c) Please explain OPG's proposal for the adjustment to nuclear liabilities when a solution is decided upon.

C2-Staff-75
Exhibit C2 / Tab 1 / Schedule 1 / p. 6

Preamble:

OPG explained that the initial value and each subsequent adjustment to the asset retirement obligation (ARO) are known as tranches. OPG also explained that the discount rate applied to each tranche is the credit adjusted risk-free rate, which is the Province of Ontario long-term bond yield rate, as at the date of each upward revision to the ARO.

Question(s):

a) Please explain any discretion or judgment management applies to select the discount rate for each tranche.

b) Please provide a table showing the calculation of the weighted average accretion rate, showing each of the nine tranches and the applicable discount rate. Please also provide the calculation of the weighted average accretion rate, including the newest tranche to reflect the change in Pickering end-of-life (EOL) effective December 31, 2020.

c) For the newest tranche(s) reflecting the change in Pickering EOL effective December 31, 2020, please explain whether there have been any changes to the methodology or assumptions used by management from those used in determining the discount rates for the previous nine tranches. Please provide supporting rationale for any changes.

C2-Staff-76
Exhibit C2 / Tab 1 / Schedule 1 / pp. 6, 9,12

Preamble:

OPG stated that in accordance with US GAAP, the discount rate used for each ARO tranche is determined using the credit adjusted risk-free rate. OPG also stated that the discount rate used to calculate the funding liabilities is determined in accordance with the ONFA, which is set at 3.25% real rate of return plus the long-term change in the Ontario Consumer Price Index (CPI), equating to 5.15% per the 2017 ONFA Reference plan. This is also the long-term target rate of return on the segregated funds.

Question(s):

a) Please provide a table showing the discount rate for each tranche, the annual weighted average accretion rate, and the annual discount rate used to calculate funding liabilities in accordance with ONFA from the first year OPG has recovered nuclear liabilities in the payment amounts to 2026.

b) Please provide supporting rationale for why the ONFA sets the annual discount rate used to calculate funding liabilities to be 3.25% real rate of return plus the long-term change in the Ontario CPI.

c) Please provide OPG's view on the appropriateness of the discount rate used in calculating the funding liabilities. Please discuss OPG's view regarding why the ONFA sets the discount rate for the funding of liabilities to be the same as the guaranteed rate of return for fund earnings (i.e. the guaranteed rate of return for the portion of the Used Fuel Segregated Fund (UFF) attributed to the first 2.23 million used fuel bundles).

d) Please explain OPG's position regarding whether it is appropriate or not to apply the same discount rate used for calculating funding liabilities as is used for the ARO.

C2-Staff-77
Exhibit C2 / Tab 1 / Schedule 1 / pp. 5, 9

Preamble:

OPG stated that the baseline cost estimates underpinning the ARO are those developed through the ONFA Reference Plan update process.

OPG also stated that the ONFA funding liabilities reflect a lifecycle view of nuclear wastes forecast over the operating span of OPG's nuclear generating facilities, including wastes not yet generated. However, the ARO considers the committed portion of the costs for OPG's nuclear liabilities, which includes lifetime variable costs associated with the wastes generated to date but excludes such costs for wastes yet to be generated.

Question(s):

a) Aside from the nuclear wastes not yet generated, please explain whether there are any other differences between the cost estimates unpinning the ARO and that in the ONFA Reference Plan. If so, please identify and explain each of these differences and how they differ between the ONFA and ARO's cost estimates.

C2-Staff-78
Exhibit C2 / Tab 1 / Schedule 1 / p. 8

Question(s):

a) Please provide the most recent AFS for the segregated funds.

C2-Staff-79
Exhibit C2 / Tab 1 / Schedule 1 / Tables 2 and 3
Exhibit C2 / Tab 1 / Schedule 1 / Attachment 1

Preamble:

Attachment 1 at Exhibit C2 / Tab 1 / Schedule 1 provides the approved quarterly contributions for the UFF and Decommissioning Segregated Fund (DF). The UFF shows contributions from March 31, 2017 to December 31, 2021. The DF shows contributions from March 31, 2017 to December 31, 2024. In Tables 2 and 3 at Exhibit C2 / Tab 1 / Schedule 1, the nuclear segregated fund balance contributions are shown from 2016 to 2026.

Question(s):

a) Please explain why the approved quarterly contributions for the UFF are only disclosed up to December 31, 2021 while the approved quarterly contributions for the DF are disclosed up to December 31, 2024 in Attachment 1 at Exhibit C2 / Tab 1 / Schedule 1.

b) Please explain how OPG has determined the forecasted contributions for 2022 to 2026.

c) Please confirm that OPG has not had to make any contributions since 2017 and is not forecasting to make any contributions up to 2026, though contributions have been rebalanced between the funds.

C2-Staff-80
Exhibit C2 / Tab 1 / Schedule 1 / Table 2
Exhibit A2 / Tab 1 / Schedule 1 / Attachment 2

Preamble:

In the 2019 AFS at Exhibit A2 / Tab 1 / Schedule 1 / Attachment 2, note 10 includes a table showing the change in OPG's portion of nuclear liabilities attributed to the prescribed facilities for the 2019 year-end of $10,425 million and for the 2018 year-end of $9,968 million. Table 2 at Exhibit C2 / Tab 1 / Schedule 1 provides the components of the ARO and shows a 2019 and 2018 year-end ARO of $10,412 million and $9,956 million, respectively.

Question(s):

a) Please explain and reconcile the difference in the 2019 and 2018 year-end ARO balances, as well as the components of the balances, between the financial statements and Table 2.

C2-Staff-81
Exhibit C2 / Tab 1 / Schedule 1 / Tables 2-3

Preamble:

Tables 2 and 3 at Exhibit C2 / Tab 1 / Schedule 1 show expenditures for used fuel, waste management and decommissioning (Line 5) in the ARO and contributions (Line 15) in the segregated funds.

Question(s):

a) Please confirm that the expenditures for used fuel, waste management and decommissioning include contributions to the segregated funds and the costs for used fuel management and L&ILW storage incurred during the stations' operating lives, which are internally funded costs to OPG.

b) Please provide the expenditures for internally funded costs from 2014 to 2026.

c) Please explain any other reasons for the difference between the expenditures and contributions.

d) Please explain how OPG forecasted internally funded costs for 2020 to 2026.

e) Please provide a table comparing the forecasted internally funded costs approved in prior OPG proceedings to actual internally funded costs incurred (or forecast to be incurred) for 2014 to 2026.

C2-Staff-82
Exhibit C2 / Tab 1 / Schedule 1 / p. 15

Preamble:

In its discussion of the methodology used (and previously approved by the OEB) to recover the costs of nuclear liabilities for the prescribed facilities, OPG explained that accounting accretion expense on the ARO and earnings on the segregated funds do not directly form part of the revenue requirement for the prescribed facilities. OPG further stated that the return component of the recovery methodology effectively replaces the net amount of accretion expense and segregated fund earnings recorded for financial accounting purposes.

Question(s):

a) Please explain whether this statement is OPG’s interpretation of the relationship between the return component and the accretion expense and segregated fund earnings. If not, please provide the basis for this statement.

b) Please provide OPG’s position on the appropriateness of replacing the net amount of accretion expense and segregated fund earnings with the return component of the recovery methodology.

C2-Staff-83
Exhibit C2 / Tab 1 / Schedule 1 / p. 17

Preamble:

OPG stated that for the segregated funds, fund earnings are forecasted at the target rate of 5.15% consistent with the discount rate per the approved 2017 ONFA Reference Plan, and fund disbursements.

Question(s):

a) Please provide the actual annual rate of return on the segregated funds from 2014 to 2020.

b) For 2014 to 2020, please provide the annual weighted average actual rate of return on the segregated funds, after capping the return of the first 2.23 million fuel bundles at the guaranteed rate of return.

C2-Staff-84
Exhibit C2 / Tab 1 / Schedule 1 / pp. 18, 21-22
Exhibit C2 / Tab 1 / Schedule 1 / Tables 1, 1a
Exhibit G2 / Tab 2 / Schedule 1 / p. 10

Preamble:

On page 18 at Exhibit C2 / Tab 1 / Schedule 1, OPG discussed income taxes associated with the prescribed facilities’ nuclear liabilities. The income tax impact for the prescribed facilities is shown in Note 2 at Exhibit C2 / Tab 1 / Schedule 1 / Table 1a, where income tax is determined by adjusting the pre-tax revenue requirement for items that are either deductible for tax purposes, but not for accounting purposes, or deductible for accounting purposes, but not for tax purposes (i.e. contributions, disbursements, expenditures).

On page 10 at Exhibit G2 / Tab 2 / Schedule 1, OPG indicated that the deferred income tax expense for Bruce is determined in accordance with generally accepted accounting principles for unregulated entities.

On page 21 at Exhibit C2 / Tab 1 / Schedule 1, OPG discussed income taxes for Bruce's nuclear liabilities. OPG stated that, as the cost elements of nuclear liabilities for Bruce are not deductible for tax purposes, they attract a deferred income tax credit. OPG further stated that Bruce Lease net revenues amounts are subject to regulatory income tax treatment through their impact on regulatory earnings before tax for the prescribed facilities. Note 3 at Exhibit C2 / Tab 1 / Schedule 1 / Table 1a, shows the impact on Bruce's income taxes. These amounts are fully offset by the income tax impact on revenue requirement as shown in Line 16 at Exhibit C2 / Tab 1 / Schedule 1 / Table 1.

Question(s):

a) Please confirm that the tax treatment for Bruce nuclear liabilities is calculated on a deferred taxes payable method, while for the prescribed facilities, taxes are calculated on a current taxes payable method. If not confirmed, please explain the tax basis for the tax calculations for each of the Bruce and prescribed facilities.

b) Please confirm that if Bruce nuclear liabilities were calculated using a current taxes payable method, the same calculation as used for the prescribed facilities as shown in Exhibit C2 / Tab 1 / Schedule 1 / Tables 1 / Line 7 would apply. If not, please explain how the tax impact for Bruce nuclear liabilities would be calculated using the current taxes payable method.

C2-Staff-85

Exhibit C2 / Tab 1 / Schedule 1 / p. 25
EB-2016-0152 / Decision and Order / December 28, 2017 / pp. 96-98

Preamble:

In the OEB's findings on the nuclear liabilities revenue requirement methodology in OPG's 2017-2021 Payment Amounts Proceeding, OPG was directed to file a jurisdictional study for cost recovery methodologies of nuclear liabilities. In the current application, OPG proposed to recover nuclear liabilities using the same methodology as approved in OPG's 2008-2009 Payment Amounts proceeding[15] and subsequent proceedings.

Question(s):

a) Given the OEB's findings on the nuclear liabilities revenue requirement methodology in the 2017-2021 Payment Amounts Proceeding and the direction to file a jurisdictional study, please explain whether OPG has considered any alternative methods of recovery for nuclear liabilities for the 2022 to 2026 period.

b) If so, please discuss OPG's consideration of these alternatives and whether any of these alternatives were deemed to be appropriate.

c) Please provide supporting rationale for OPG's proposal to continue to use the methodology as approved in OPG's 2008-2009 Payment Amounts proceeding.

d) If OPG was approved to recover nuclear liabilities using a different methodology than currently proposed, please explain whether there would be any transitional matters to consider and what these matters may be.

C2-Staff-86
EB-2016-0152 / Decision and Order / December 28, 2017 / pp. 96-98
EB-2016-0152 / Undertaking J20.7

Preamble:

In the OEB's findings on the nuclear liabilities revenue requirement methodology in OPG's 2017-2021 Payment Amounts proceeding, the OEB makes reference to amounts recovered pertaining to nuclear liabilities compared to requirements as provided in Undertaking J20.7 of that proceeding.

Question(s):

a) Please provide an update to the chart provided in EB-2016-0152 / Undertaking J20.7 so that the chart reflects the April 1, 2008 to December 31, 2026 period, including forecasted amounts as applicable.

[15] EB-2007-0905.

Nuclear Liability Cost Recovery Jurisdictional Study

C2-Staff-87
Exhibit C2 / Tab 1 / Schedule 1 / Attachment 2

Question(s):

a) Page 37 of the Nuclear Liability Cost Recovery Jurisdictional Study (the Jurisdictional Study) states, “In our US research we found in many instances that the accounting changes on adoption of FAS 143 were discussed in regulatory proceedings and that the utility commissions involved did not change how costs were recovered in rates.” For those utilities noted (e.g. South Carolina, Florida, Georgia, Minnesota, North Carolina) where utility commissions did not require a change in cost recovery methodology upon adoption of FAS 143, please provide any further reasons beyond those noted in the report as provided by the utility commissions in deciding not to change how costs were recovered in rates.

b) Page 10 of the Jurisdictional Study discusses recovery methodologies including the “forward-looking funding requirements” and “accounting expense” methodologies. The forward-looking funding requirements methodology is based on amounts contributed to set-aside funds. The accounting expense methodology is based on expenses recognized in the financial statements. Please discuss OPG’s views on whether the total recoveries under the two methodologies for OPG’s nuclear liabilities should conceptually be equal after the nuclear liabilities are fully decommissioned.

c) Page 57 of the Jurisdictional Study indicates that for the utilities and jurisdictions reviewed in the U.S., recovery of nuclear decommissioning costs for investor-owned utilities is based on forward-looking funding approach. During KPMG LLP (KPMG)’s review of various jurisdictions in the U.S. for the purpose of selecting the jurisdictions to focus on, did KPMG come across any jurisdictions that recovered decommissioning costs based on an accounting approach? If so, please identify these jurisdictions and provide further details on the recovery methodology.

Exhibit D – Capital Projects

Exhibit D2 – Nuclear Capital Projects

Nuclear Operations Capital

D2-Staff-88

Exhibit D2 / Tab 1 / Schedule 2 / Tables 4a, 4b

Preamble:

Based on Tables 4a and 4b at Exhibit D2 / Tab 1 / Schedule 2, OEB staff has derived the table below that shows total differences between actual and OEB-approved capital expenditures between 2017 and 2021, excluding DRP.

OEB staff calculates that OPG spent $642.8 million more on nuclear operations capital expenditures, excluding DRP, between 2017 and 2021 than was approved by the OEB.

		(a)	(b)	(c)	(d)	(e)
		2017	**2018**	**2019**	**2020**	**2021**
1	OEB Approved	279.1	258.0	282.4	278.5	199.3
2	Actual*	354.3	381.9	395.3	401.0	407.5
3	Difference (2 minus 1)	75.2	123.9	112.9	122.6	208.2

Question(s):

a) Please confirm that OPG spent $642.8 million more on nuclear operations capital expenditures, excluding DRP, between 2017 and 2021 than was approved by the OEB.

b) If OEB staff's calculation is incorrect, please provide a corrected version. Where applicable, please include citations to applicable tables and cells elsewhere in the application.

D2-Staff-89
Exhibit D2 / Tab 1 / Schedule 2 / Table 2
Exhibit D3 / Tab 1 / Schedule 2 / Tables 1a-7

Question(s):

a) Please confirm that the values in Exhibit D2 / Tab 1 / Schedule 2 / Table 2 do not include the nuclear allocated support services capital values from Exhibit D3 / Tab 1 / Schedule 2 / Tables 1a-7. Otherwise, please clarify.

b) Please confirm that none of the capital expenditures reflected in Exhibit D2 / Tab 1 / Schedule 2 / Table 2 were classified as DRP-related capital expenditures in OPG's 2017-2021 Payment Amounts Proceeding (and included as part of the $12.8 billion DRP budget).

D2-Staff-90
Exhibit D2 / Tab 1 / Schedule 2 / pp. 11-26
Exhibit D2 / Tab 1 / Schedule 2 / Tables 4a and 4b

Preamble:

OPG's nuclear operations capital expenditures were higher than OEB-approved amounts in each year between 2017 and 2021. On various instances at Exhibit D2 / Tab 1 / Schedule 2 / pp. 11-26, OPG attributed this to increased spending on Portfolio Projects (Allocated). OPG also noted that new projects play an important role in the variance. Based on Exhibit D2 / Tab 1 / Schedule 2 / Tables 4a and 4b, OEB staff estimates that higher spending on Darlington NGS accounted for nearly three quarters of the higher-than-approved spending on Portfolio Projects (Allocated).

Question(s):

a) Please clarify what "new projects" means in the context of the preamble above.

b) Please clarify what "Supplemental In-Service Forecast" means in the context of Exhibit D2 / Tab 1 / Schedule 2 / Tables 4a and 4b.

c) What conclusions does OPG draw from the capital expenditures variances outlined at the references above? What have been the root causes of variances between 2017 and 2021? Has OPG perceived a common thread of root causes across different projects? Is the direction of the variances mixed, or are the variances usually positive (i.e. over-variances)?

D2-Staff-91
Exhibit D2 / Tab 1 / Schedule 2 / Table 2

Question(s):

a) Please provide a breakdown of all 2016 to 2026 Operations and Project Support capital expenditures based on which site / facility they are mainly attributable to.

b) Capital expenditures in the amounts of $9.3 million in 2021 and $0.4 million in 2022 are planned for Pickering NGS. Please specifically identify the project or initiative that these funds are allocated to. In the response, please justify the need for these capital expenditures considering the Pickering Optimized Shutdown in 2025.

D2-Staff-92
Exhibit D2 / Tab 1 / Schedule 3 / Tables 4a and 4b

Preamble:

Based on Exhibit D2 / Tab 1 / Schedule 3 / Tables 4a and 4b, OEB staff have derived the table below that shows the total differences between actual and OEB-approved nuclear operations in-service amounts between 2017 and 2021, excluding DRP.

OEB staff calculates that OPG made $313.9 million more in nuclear operations in-service additions, excluding DRP, between 2017 and 2021 than were approved by the OEB.

		(a)	(b)	(c)	(d)	(e)
		2017	**2018**	**2019**	**2020**	**2021**
1	OEB Approved	431.1	319.2	346.9	220.2	163.5
2	Actual*	464.4	390.3	326.1	282.2	331.8
3	Difference (2 minus 1)	33.3	71.1	-20.8	62.0	168.3

Question(s):

a) Please confirm that OPG made $313.9 million more in nuclear operations in-service additions, excluding DRP, between 2017 and 2021 than were approved by the OEB.

b) If OEB staff's calculation is incorrect, please provide a corrected version. Where applicable, please include citations to applicable tables and cells elsewhere in the application.

D2-Staff-93

Exhibit D2 / Tab 1 / Schedule 3 / pp. 42-52
Exhibit D2 / Tab 1 / Schedule 3 / Tables 4a-4b

Preamble:

OPG identified various general factors that can affect both the amount of an in-service declaration and its timing at Exhibit D2 / Tab 1 / Schedule 3 / pp. 42-52. OPG identified the individual projects that contributed to the variances and makes note of what appear to be proximate causes of the variances.

OPG also stated that overall, based on 3 years of actuals and 2 years of budget information, it expects capital in-service additions to exceed the OEB approved amount, and to be roughly equal to OPG's forecast before the OEB in-service forecast adjustment as directed in OPG's 2017-2021 Payment Amounts Proceeding.

Question(s):

a) Please confirm whether the in-service variances described at Exhibit D2 / Tab 1 / Schedule 3 / pp. 42-52 are relative to OEB-approved amounts.

b) What conclusions does OPG draw from the in-service variances outlined at the references above? What have been the root causes of variances? Has OPG perceived a common thread of root causes across different projects? Is the direction of the variances mixed, or are they usually positive (i.e. over-variances)?

D2-Staff-94

Exhibit D2 / Tab 1 / Schedule 1 / Attachment 1 / p. 2

Preamble:

OPG noted that project close-out includes the preparation of a project close out report to document final costs and lessons learned.

Question(s):

a) If a project close out report was prepared for the D2O Storage Project, please file the report. If not, please explain why one was not prepared.

D2-Staff-95
Exhibit D2 / Tab 1 / Schedule 1 / Attachment 1 / p. 2

Question(s):

a) Please clarify how the Post Implementation Review relates to the project close out report.

b) If a Post Implementation Review was prepared for the D2O Storage Project, please file the review. If not, please explain why one was not prepared.

D2-Staff-96
Exhibit D2 / Tab 1 / Schedule 1 / p. 9

Question(s):

a) Please clarify the difference between a “full release” and “partial release” and describe why one might be requested and / or approved versus the other.

D2-Staff-97
Exhibit D2 / Tab 1 / Schedule 1 / p. 10

Question(s):

a) Please advise whether OPG used a Collaborative Front End Planning program at the time of OPG’s 2017-2021 Payment Amounts Proceeding or is it a program that has been implemented since that time. If it was implemented after OPG’s 2017-2021 Payment Amounts Proceeding, please indicate the approximate timing and provide reasoning for its implementation.

D2-Staff-98
Exhibit D2 / Tab 1 / Schedule 1 / p. 12

Preamble:

OPG stated that by creating the Enterprise Projects Organization (EPO) and centralizing expertise and processes, OPG has enabled increased consistency and inter business-unit collaboration, strengthening staff proficiency, leveraging expertise, and implementing processes targeted at improving OPG’s project performance.

Question(s):

a) Please provide examples of nuclear capital projects that the EPO has worked on and, in the context of those projects, generally describe its role in enabling increased consistency and inter business-unit collaboration, strengthening staff proficiency, leveraging expertise, and implementing processes targeted at improving OPG’s project performance.

b) How widely is the EPO involved in nuclear capital projects over the 2022-2026 Custom IR term?

c) Please clarify why major project execution groups from across the Nuclear and Renewable Generation business units were integrated into the EPO as part of the organizational structure realignment in the second half of 2020.

d) How widely are the updated nuclear project management processes and tools used across the nuclear capital projects over the 2022-2026 Custom IR term?

e) Please clarify the functional relationship between the Project Management Centre of Excellence and the EPO. For example, has the EPO replaced the Project Management Centre of Excellence?

D2-Staff-99
Exhibit D2 / Tab 1 / Schedule 1 / p. 13

Preamble:

OPG described enhancements to the phase-gating process and stated that the introduction of thorough control check points (or gates) provides the Project Management Oversight Committees (PMOC) with the opportunity to challenge project readiness before the project progresses to the next phase, or determine if a project should continue to be endorsed.

OPG further stated that the EPO's estimating of nuclear project cost and schedules was enhanced in 2018.

Question(s):

a) Please clarify how the phase-gating process was enhanced and when. For instance, did the "opportunity to challenge project readiness" not exist for OPG for projects included OPG's 2017-2021 Payment Amounts Proceeding? What has changed since the 2017-20221 Payment Amounts Proceeding?

b) What led OPG to enhance its nuclear project cost and schedule estimation in 2018?

c) How does OPG evaluate the effectiveness of its nuclear project cost estimates? For example, what is the baseline and criteria that OPG uses to evaluate its estimates?

d) What is the practical consequence to OPG of ineffective project cost estimation?

D2-Staff-100
Exhibit D2 / Tab 1 / Schedule 1 / p. 14

Preamble:

OPG stated that the project portfolio management within the Project Excellence Initiative is focused on improving the delivery of the portfolio on budget and schedule by enhancing consideration of project interdependencies, and site and fleet priorities.

Question(s):

a) Please clarify what OPG means by the term "project portfolio management" in the above reference. Is it an approach / technique / method / etc.? Does it differ from project management, or does it refer to project management of a portfolio of projects?

b) Is project portfolio management within the Project Excellence Initiative a new or enhanced initiative that was introduced since OPG's 2017-2021 Payment

Amounts Proceeding? If so, when and how widely is it involved in nuclear capital projects over the Custom IR term?

D2-Staff-101
Exhibit D2 / Tab 1 / Schedule 1 / p. 15

Question(s):

a) At a high-level, please clarify how the “work allocation approach” differs from and improves on the approach used before its implementation.

D2-Staff-102
Exhibit D2 / Tab 1 / Schedule 1 / Attachment 1 / pp. 2-3

Question(s):

a) As both an absolute total and as a percentage, please identify the number of projects that OPG has completed within the AACE International (AACE) confidence interval applied to each individual project original estimate since the completion of OPG’s 2017-2021 Payment Amounts proceeding.

D2-Staff-103
Exhibit D2 / Tab 1 / Schedule 1 / p. 15

Preamble:

OPG stated that in 2019, KPMG was engaged to conduct an independent audit of OPG's Nuclear Projects and Modifications (P&M) organization (KPMG Audit).

Elsewhere in Exhibit D2 / Tab 1 / Schedule 1 / p. 15, OPG referred to other organizations, including the Asset Management Oversight Committees, PMOC, EPO and Project Management Center of Excellence.

Question(s):

a) Please clarify the meaning of the term Nuclear P&M organization and how it relates to other organizations involved in nuclear projects at OPG, including those cited above.

D2-Staff-104
Exhibit D2 / Tab 1 / Schedule 1 / Attachment 2 / p. 3

Preamble:

KPMG stated that the objective of the audit is to assess the adequacy of P&M's project controls, including associated processes and procedures implemented in January 2018.

Question(s):

a) Please clarify the significance of the date January 2018 to the scope of the KPMG Audit referenced above and clarify why it was used as the starting point for the KPMG Audit.

D2-Staff-105
Exhibit D2 / Tab 1 / Schedule 1 / Attachment 2

Preamble:

In OPG's 2017-2021 Payment Amounts Proceeding, OPG filed reports prepared by Burns McDonnell / Modus Strategic Solutions for the Nuclear Oversight Committee of OPG's Board of Directors. OPG also filed internal audit reports that were completed by OPG itself.

Question(s):

a) Please provide a copy of any reports / audit reports prepared by Burns McDonnell / Modus Strategic Solutions for OPG's Board of Directors since 2016 (that have not already been filed by OPG in the current application).

b) Is Burns McDonnell / Modus Strategic Solutions still retained by OPG to provide independent analysis of OPG nuclear project management effectiveness? If not, who is the successor to Burns McDonnell / Modus Strategic Solutions?

c) Please provide a copy of any reports / audit reports prepared by any successor of Burns McDonnell / Modus Strategic Solutions for the Nuclear Oversight Committee of OPG's Board of Directors since 2016 (that have not already been filed by OPG in the current application).

d) Please file OPG's Project Controls Audit – Project & Modifications Group Internal Audit Report dated March 9, 2016 on the record of this application.

e) Please provide the first execution business case budget and the final, or expected final, cost for all of the projects that were reviewed in the OPG's Project Controls Audit – Project & Modifications Group Internal Audit Report. Please also provide the actual or expected final in-service date for these projects.

f) Please file the 2nd Quarter 2014 Report to the Nuclear Oversight Committee of OPG's Board of Directors on the record of this application.

g) Please file the Supplemental Report to the Nuclear Oversight Committee – 2nd Quarter 2014 on the record of this application.

D2-Staff-106
Exhibit D2 / Tab 1 / Schedule 3 / Tables 1a-1d

Question(s):

a) Please clarify what is meant by "start date" in column (e) of the tables referenced.

b) Please clarify what is meant by "total in-service" in column (i) of the tables referenced. How does it differ from "total project cost" in column (g)? Please explain why for some projects that are completed (and fully in-service) is the total project cost different than the total in-service amount. Please advise whether OM&A costs are included in the total project costs.

c) Please confirm which amount is approved in a first execution business case: total project cost or the total in-service amount?

d) Where the "total project cost" in column (g) is different from the first execution business case value shown in column (i) or (j), does this mean that the project has had an updated business case since its first execution business case? Please explain.

e) What is the difference between the total project cost in column (g) and the total project cost EB-2016-0152 in column (h)?

f) Why does the sum of "total in-service LTD" (column (j)) and "in-service IR term" (column (k)) sometimes not equal the "total in-service" value from column (i)?

Please confirm that this means that there are in-service amounts expected post-2026.

D2-Staff-107
Exhibit D2 / Tab 1 / Schedule 3 / Tables 1a, 1c, 1d

Question(s):

a) Please clarify why there are 22 instances in the tables referenced above where there are in-service amounts proposed for the Custom IR term (together totaling approximately $768 million), but there is no first execution business case?

D2-Staff-108
Exhibit D2 / Tab 1 / Schedule 3 / Tables 2a-2g
Exhibit D2 / Tab 1 / Schedule 3 / Table 3

Question(s):

a) Why do none of the tables referenced above include a column that shows in-service LTD similar to Tables 1a through 1d?

b) Why do none of the tables referenced above include a column what shows first execution business case similar to Tables 1a through 1d?

D2-Staff-109
Exhibit B3 / Tab 3 / Schedule 1 / Table 2
Exhibit D2 / Tab 1 / Schedule 3 / Table 4b

Preamble:

The first reference above includes in-service amounts for Pickering NGS between 2022 and 2026. The second reference shows zero in-service amounts for Pickering NGS between 2022 and 2026.

Question(s):

a) Please provide the in-service amounts for Pickering NGS between 2022 and 2026.

b) Which of the above-referenced tables is correct? If both, please clarify. Otherwise, please provide a revised table(s).

D2-Staff-110
Exhibit D2 / Tab 1 / Schedule 3 / p. 3

Preamble:

OPG stated that some of the 53 projects in the project portfolio (unallocated) category will move from the project identification and initiation phases into the project definition or execution phase as part of the ongoing portfolio management process.

Question(s):

a) Please clarify the total annual in-service amounts proposed between 2022 and 2026 for portfolio (unallocated) projects that will move into the project initiation or execution phase.

D2-Staff-111
Exhibit D2 / Tab 1 / Schedule 3

Question(s):

a) Please complete the following table for all nuclear operations capital that are: (i) ongoing from OPG's 2017-2021 Payment Amounts Proceeding; (ii) completed / deferred / cancelled since OPG's 2017-2021 Payment Amounts Proceeding; and (iii) not included in OPG's 2017-2021 Payment Amounts Proceeding.

		a	b	c	d	e
		Total Number of Projects	**Number of Projects which have Final In-Service Before or During IR Term**	**Total Project Cost ($M)**	**Total 1st Execution Business Case ($M)**	**Total Cumulative In-Service Additions 2022-2026 ($M)**
1	Tier 1					
2	Tier 2					
3	Tier 3					
4	Unallocated					
5	Total					

D2-Staff-112

Exhibit D2 / Tab 1 / Schedule 3 / Tables 1a-2g

Question(s):

a) Please complete the following table, based on Tables 1a-2g at Exhibit D2 / Tab 1 / Schedule 3.

		a	b	c	d	e	f	g
	Projects	**2017 - 2021 OEB approved nuclear operations in-service additions**	**2017 - 2021 actual nuclear operations in-service additions**	**2017 - 2021 actual vs OEB-approved nuclear operations in-service additions (b minus a)**	**2022-2026 proposed nuclear operations in-service additions**	**Total 1st Execution Business Case**	**Total Project Cost**	**Number of Projects**
1	From EB-2016-0152							
2	Completed / Deferred / Cancelled							
3	Not in EB-2016-0152							
4	**TOTAL**							

		a	b	c	d	e	f	g
	Division Totals	**2017 - 2021 OEB approved nuclear operations in-service additions**	**2017 - 2021 actual nuclear operations in-service additions**	**2017 - 2021 actual vs OEB-approved nuclear operations in-service additions (b minus a)**	**2022-2026 proposed nuclear operations in-service additions**	**Total 1st Execution Business Case**	**Total Project Cost**	**Number of Projects**
5	Darlington							
6	Pickering							
7	Operations and Project Support							
8	**TOTAL**							

<u>D2-Staff-113</u>

Exhibit D2 / Tab 1 / Schedule 3 / Tables 1a-1d

Question(s):

a) Please populate the following table for all projects listed in Table 1a through Table 1d of Exhibit D2 / Tab 1 / Schedule 3.

Project Name	In-service Date	In-service Date – EB-2016-0152	Total Project Cost ($M)	Total 1st Execution Business Case ($M)	Delta ($M)	In-service amount ($M) – EB-2016-0152	IR Term In-service amount ($M)	Total In-service amount ($M)
(a)	(b)	(c)	(d)	(e)	(f) = (d) –(e)	(g)	(h)	(i)

b) Please highlight any projects in the table requested in part (a) of this interrogatory for which the total project cost was, or is expected, to be greater than 10% above the first execution business case. Please also identify the specific reason behind the cost overrun of each of these projects. In the response, please include a summary of the actions taken on these projects to limit the cost overruns.

c) For each project listed in the table requested in part (a) of this interrogatory, please provide the specific OPG organization or external contractor responsible for: (i) project planning, (ii) project oversight and (iii) project execution. In the response, please indicate whether any of these organizations have been replaced or substituted during any project stage.

d) Please provide the contracting strategies used to obtain external resources (i.e. labour, materials, services, etc.) for each project listed in the table requested in part (a) of this interrogatory

e) For each project listed in the table requested in part (a) of this interrogatory, please identify whether OPG's P&M organization was involved in any capacity. In the response, please outline the specific involvement of OPG's P&M organization on each project, where applicable.

f) For any projects listed in the table requested in part (a) of this interrogatory where OPG's P&M organization was involved, please identify the total cost associated with each aspect (e.g. planning, oversight, execution, etc.) that P&M was responsible for or involved with in both absolute dollar amounts and as a percentage of the approved project budget. Please use the tabular format provided below.

Project Name	Project Aspect	P&M Project Costs ($M)	P&M Project Costs as Percentage of Approved Project Budget (%)

D2-Staff-114
Exhibit D2 / Tab 1 / Schedule 3 / pp. 2-3, 55-59

Question(s):

a) Many Darlington Tier 1 Capital Projects involve the replacement or refurbishment of aging or obsolete components (e.g. valves, cables, etc.). Please identify whether the execution of any of the Darlington Tier 1 Capital Projects will be executed during the DRP. In the response, please confirm that the amounts were not previously included in the budget for the DRP.

b) A business case for Projects #31518, #31542, #33631, #33877, #80022, and #80144 are included, however financial and project status updates are not provided. Please provide the financial and project status updates for these projects. In the response, please explain any financial variances from the forecast budget for each.

D2-Staff-115
Exhibit D2 / Tab 1 / Schedule 3 / pp. 11, 37

Question(s):

a) Please confirm whether Project #83828 Fleet Monitoring Initiative is applicable to all OPG facilities, including hydroelectric and nuclear generating stations. Please provide a breakdown of this project's cost based on each generating facility where it will be deployed. In the response, please comment on the rationale for implementation in any generating facility nearing end of commercial operations.

b) Please explain the difference between Project #33819 Darlington Vibration Monitoring System Replacement for Major Pump-sets and Project #83828 Fleet Monitoring Initiative and whether there is any overlap between the projects. In the response, please identify whether there are any potential cost savings or synergies to be gained by completing Project #33819 in parallel with Project #83828.

c) Please explain why the original scope for Project #33819 did not include vibration monitoring of auxiliary shutdown cooling pumps and connection to OPG's Local Area Network. In the response, please identify how much of the $31.6 million increase in the original project estimate is attributable to this additional scope.

D2-Staff-116
Exhibit D2 / Tab 1 / Schedule 3 / p. 35

Question(s):

a) OPG identified the following three items that led to Project #31412 cost increases: (i) additional project management and OPG oversight costs, (ii) additional Engineering, Procurement, Construction contract costs, and (iii) foreign exchange rate variance. Please provide the discrete project cost increases associated with each of these three items. In the response, please explain the reason why foreign exchange rate variances resulted in cost increases and what actions were taken to mitigate this factor.

b) Please explain any additional factors that led to the observed cost increases on Project #31412. In the response, please outline all mitigating actions in response to all factors that contributed to cost increases.

D2-Staff-117
Exhibit D2 / Tab 1 / Schedule 3 / pp. 19, 21

Question(s):

a) Please provide the full amount that was transferred from Projects #49158 and #49299 to Project #31508 Darlington Fukushima Phase 1 Beyond Design Basis Event Emergency Mitigation Equipment.

b) Please confirm that Project #31508 was completed for a total of $55.5 million and was overbudget by $2.6 million.

c) Please explain the reasons for why Project #31508 was completed overbudget and the mitigating actions that were taken to control budgetary overruns.

D2-Staff-118
Exhibit D2 / Tab 1 / Schedule 3 / p. 29

Question(s):

a) For Project #31516 Darlington Station Fluorescent Lighting Fixtures Retrofit, please explain why the evaluation of LED technology and its availability was not completed prior to the approval of the developmental business case summary (BCS).

b) Please provide a cost estimate of completing custom LED retrofits. Please comment as to whether the same $9.3 million increase from the Class 4 project estimate would have been incurred had the custom LED retrofit approach been implemented.

c) Please provide an estimate of the annual cost savings expected from the switch to LED lights. In the response, please confirm that these savings have been captured in the proposed OM&A costs.

D2-Staff-119
Exhibit D2 / Tab 1 / Schedule 3 / p. 25

Question(s):

a) Please confirm that Project #31524 Darlington Roof Replacement is currently expected to cost $78.5 million more than the Initiation Phase estimate of $36.3 million.

b) OPG noted that "ESMSA vendors responded with compliant quotations, which were reviewed by OPG's estimating group who confirmed that the prices were reasonable and within industry estimating guidelines. As the contract price was higher than expected…". Considering the above statement, please explain the rationale behind the initial $36.3 million estimate.

c) Please confirm that the costs associated with the completed preliminary design and pilot are included in the forecast project cost of $116.9 million. In the response, please identify how much has been spent to date.

D2-Staff-120
Exhibit D2 / Tab 1 / Schedule 3 / pp. 19, 55

Question(s):

a) Please breakdown the $138.6 million initial estimate for the Darlington Water Treatment Plant into the capital, fixed operations, and scheduled rehabilitation elements. Please include an estimate for the monthly consumable variable costs. In the response, please indicate the confidence level of all estimates.

b) Please confirm whether the costs associated with Project #31535 Darlington Water Treatment Plant Interconnections are included in the total $138.6 million budget for the Darlington Water Treatment Plant.

c) A business case for Project #31535 is included, however financial and project status updates are not provided. Please provide the financial and project status updates for Project #31535. In the response, please explain any financial variances from the forecast budget.

D2-Staff-121
Exhibit D2 / Tab 1 / Schedule 3 / p. 26

Question(s):

a) Project #31544 Darlington Radiation Detection Equipment Obsolescence will be completed by three separate engineering, procurement, and construction (EPC) contractors. Please further elaborate on why it was decided to award three separate EPC contracts for one project. In the response, please comment on any direct or indirect additional costs associated with engaging three separate vendors on Project #31544.

b) OPG noted that “the subsequent BCS incorporated a more complex design than initially assumed, augmented with a more accurate and detailed estimate provided by a third party”. Please comment as to why initial assumptions were too simple and why a more accurate and detailed estimate was not sought for in the initial BCS. In the response, please comment on why OPG’s internal estimating group did not complete the detailed estimate.

D2-Staff-122
Exhibit D2 / Tab 1 / Schedule 3 / pp. 17, 31, 40

Question(s):

a) The base maintenance initiative implemented in 2008 on the Emergency Power System did not include the circuit breaker, magnetic component, peripheral, and capacitor replacement. Please explain the rationale for omitting these components. In the response, please identify whether the lifespan of the existing Emergency Power System was shortened by the omission of the noted parts.

b) Regarding Project #80036 Darlington R22 Refrigerant Air Conditioning Unit Replacement, OPG noted that “the ESMSA vendors responded with compliant quotes, which were higher than OPG expected in the Definition BCS. These quotes were reviewed by OPG’s estimating group, which confirmed that the prices were reasonable and within industry estimating guidelines.” Considering the above, please elaborate as to why the estimate in the original BCS was less than what OPG’s estimating group deemed to be reasonable.

D2-Staff-123
Exhibit D2 / Tab 1 / Schedule 3 / pp. 9, 30

Question(s):

a) Scope was transferred from Project #83298 to Project #80023, which contributed to the cost increase associated with Project #80023. Please confirm how much of the $22.3 million cost increase of Project #80023 can be attributed to this scope transfer.

b) Please quantify the reduction in the forecast budget of Project #83298 associated with the transfer of scope to Project #80023.

c) Please identify the collective net savings across Project #83298 and Project #80023 expected from the “anticipated project execution efficiencies” of the scope transfer.

d) Please provide an estimate of the annual cost savings expected from the switch to the new valves with reduced maintenance requirements. In the response, please confirm that these savings have been captured in the proposed OM&A costs.

D2-Staff-124
Exhibit D2 / Tab 1 / Schedule 3 / p. 32

Question(s):

a) Please confirm whether OPG intends to use “off-the-shelf” materials for Project #80063 Darlington Standby Generators Protective Relay Replacement.

b) Regarding Project #80063, OPG noted that the EPC vendor estimates for detailed design to accommodate the integration and installation of the “off-the-shelf" materials were greater than estimates made at the time of preparation of the Definition BCS. The EPC vendor estimates were assessed by OPG's estimating group, who confirmed that the price was reasonable and within industry estimating guidelines. Considering the above, please elaborate as to why the estimate in the original BCS was less than what OPG's estimating group deemed to be reasonable.

D2-Staff-125
Exhibit D2 / Tab 1 / Schedule 3 / p. 41

Question(s):

a) Please identify whether the review completed by the Northeast Power Coordinating Council (NPCC) Task Force and the IESO on Project #40691 Pickering B Emergency Power Generator and Main Output Transformer Protective Relay Replacement had an impact on project budget, and if so whether this impact became known after the Class 2 cost estimate of $11.0 million was established.

b) Please confirm whether the NPCC Task Force has accepted the scope of Project #40691.

Darlington Refurbishment Program

D2-Staff-126
Exhibit D2 / Tab 2 / Schedule 1 / p. 1
Exhibit D2 / Tab 2 / Schedule 9 / Tables 5a-5b
Exhibit F2 / Tab 7 / Schedule 1 / Table 1

Preamble:

OPG referenced a four-unit, program-level control budget of $12,800 million for the DRP.

On the basis of Tables 5a and 5b at Exhibit D2 / Tab 2 / Schedule 9, OEB staff calculates that the total actual and proposed DRP-related in-service additions for the 2016-2026 period are $12,249.4 million. On the basis of Table 1 at Exhibit F2 / Tab 7 / Schedule 1, OEB staff calculates that the total actual and proposed DRP-related OM&A costs for the 2016-2026 period are $241.0 million. Therefore, the total DRP cost (both capital and OM&A) for the 2016-2026 period is $12,490.4 million.

Question(s):

a) Please complete the following table with actual and planned / projected DRP costs. An "other" category is provided if needed to capture cost types not already captured in previous categories. If the "other" category is used, please provide explanatory notes.

		a	b	c	d	f
	($M)	**2016 and prior**	**2017-2021**	**2026-2026**	**2027 and later**	**Total** (a + b + c + d)
1	**OM&A**					
2	**In-Service Capital**					
3	**Other / TBD cost**					
4	**Total** (1 + 2 + 3)					

b) Please comment on how the total actual and projected costs in the table above compare against the DRP's $12,800 million four-unit, program-level control budget and OEB staff's calculation set out in the preamble.

c) Please complete the following table with OEB-approved DRP costs.

		a	b	c
	($M)	**2016 and prior**	**2017-2021**	**Total**
1	**OM&A**			
2	**In-Service Capital**			
3	**Total** (1 + 2)			

d) Please complete the following table to summarize any variance between actual DRP costs and OEB-approved DRP costs.

		a	b	c
	($M)	**2016 and prior** (Actual minus OEB-approved)	**2017-2021** (Actual minus OEB-approved)	**Total** (a + b)
1	**OM&A**			
2	**In-Service Capital**			
3	**Total** (1 + 2)			

D2-Staff-127
Exhibit D2 / Tab 2 / Schedule 2 / p. 2

Preamble:

OPG stated that relative to the OEB approved in-service amounts in OPG's 2017-2021 Payment Amounts Proceeding of $5,177.4 million for the refurbishment of Unit 2 there is a forecast variance of $132.7 million or 2.5%.

Question(s):

a) Please provide the total actual cost of the Unit 2 refurbishment. Please complete the table below. The "other" category is provided if needed to capture costs not already captured in previous categories. If the "other" category is used, please provide explanatory notes.

		1	2	3
	($M)	**In-Service Capital**	**OM&A**	**Total** (1 + 2)
a	**Unit 2**			
b	**EIS, F&IP and SIO**			
c	**Definition Phase**			
d	**Other**			
e	**Total** (a + b + c + d)			

b) Please provide the OEB-approved costs for Unit 2. Please complete the table below. The "other" category is provided if needed to capture costs not already captured in previous categories. If the "other" category is used, please provide explanatory notes.

		1	2	3
	($M)	**In-Service Capital**	**OM&A**	**Total** (1 + 2)
a	**Unit 2**			
b	**EIS, F&IP and SIO**			
c	**Definition Phase**			
d	**Other**			
e	**Total** (a + b + c + d)			

c) Please complete the following table to summarize the variance between actual Unit 2 refurbishment costs and OEB-approved Unit 2 refurbishment costs.

		1	2	3
	($M)	**In-Service Capital** (Actual minus OEB-approved)	**OM&A** (Actual minus OEB-approved)	**Total** (1 + 2)
a	**Unit 2**			
b	**EIS, F&IP and SIO**			
c	**Definition Phase**			
d	**Other**			
e	**Total** (a + b + c + d)			

D2-Staff-128

Exhibit D2 / Tab 2 / Schedule 2 / p. 2
Exhibit D2 / Tab 2 / Schedule 7 / Attachment 1 / Appendix 2
Exhibit D2 / Tab 2 / Schedule 9 / Table 2 / Column G
Exhibit B3 / Tab 3 / Schedule 1 / Table 2 / Line 2 / Column C

Preamble:

In the first reference, OPG noted that relative to the OEB-approved amount of $5,177.4 million for the refurbishment of Unit 2 (including the Definition Phase), Early-In-Service projects, Facilities and Infrastructure Projects (F&IP) and Safety Improvement Opportunities (SIO), there is a forecast variance of $132.7 million.

The second reference provides a four-unit cost summary and states that Unit 2 cost $3,417 and that “Pre-Reqs (Unit 0/D/F&S)” cost $2,764 million for an apparent total of $6,181 million.

The third reference suggests the refurbishment of Unit 2 cost at least $4,761.8 million (row 5) or $6,006.4 million (row 18).

Question(s):

a) Please clarify what it cost to refurbish Unit 2 and reconcile with the Unit 2 refurbishment costs cited in the first three references noted above.

b) Please explain the difference between the $132.7 million cited in the first reference and the $134.6 million adjustment to DRP-related gross plant at the fourth reference.

D2-Staff-129
Exhibit D2 / Tab 2 / Schedule 7 / p. 9 / Chart 2

Question(s):

a) Using the chart referenced above as the starting point, please add a column showing the actual costs of Unit 2 refurbishment and revise the row called "Total Envelope In-Service Amount for Remaining Units" as applicable. Please show Unit 2 costs on a directly comparable basis to those shown in the chart for units 3, 1 and 4. If additional columns are required (e.g. to separately show Definition Phase costs, etc.), please include those additional columns.

D2-Staff-130
Exhibit D2 / Tab 2 / Schedule 2 / p. 6

Preamble:

OPG stated that the analysis of the Unit 2 schedule performance shows that without the challenges experienced on lower feeder pipe installation, the Unit 2 refurbishment outage would have been completed on schedule.

Question(s):

a) What was the incremental impact, if any, of the schedule delay on the Unit 2 refurbishment cost?

D2-Staff-131
Exhibit D2 / Tab 2 / Schedule 2 / p. 10
Exhibit D2 / Tab 2 / Schedule 3

Preamble:

The first reference above outlines various lessons learned on the feeder series during the execution of Unit 2, including delays in the receipt of new feeders, higher than expected weld failure rates, congestion on the reactor face and upper feeder pipe installation complexity. The second reference above describes collaboration efforts with Bruce Power.

Question(s):

a) What was the relative impact of each of the challenges identified above on the timing and cost performance of Unit 2 refurbishment? For instance, which factor had the largest impact and which had the least impact?

b) What was the cost and schedule impact of congestion on the reactor face in particular?

c) Please comment on why OPG's work with the mock-reactor or its collaboration with Bruce Power did not prepare OPG for the congestion on the reactor face experienced during Unit 2 refurbishment?

D2-Staff-132
Exhibit D2 / Tab 2 / Schedule 2 / p. 15
Exhibit D2 / Tab 2 / Schedule 8 / p. 20

Preamble:

OPG stated that its Board of Directors reassessed the type of oversight required for the DRP and decided to engage the Refurbishment Construction Review Board (RCRB) to continue to provide independent oversight services for the remainder of the DRP.

OPG also stated that the RCRB is normally comprised of three to five external members, typically with support from one internal OPG member.

OPG stated that the RCRB delivered 14 reports over the course of the Unit 2 refurbishment.

Question(s):

a) Please describe the types of changes in oversight for the DRP that OPG's Board of Directors determined were required in deciding to engage the RCRB instead of Burns McDonnell / Modus Strategic Solutions.

b) Please clarify what is meant by "external members."

c) When was the RCRB engaged to provide independent oversight services for the remainder of the DRP?

d) What is the RCRB's mandate?

e) Please provide all RCRB reports referenced above that have not already been filed as part of this application.

f) Please also file any RCRB reports that were completed after the Unit 2 refurbishment was completed that have not already been filed as part of this application.

<u>D2-Staff-133</u>
Exhibit D2 / Tab 2 / Schedule 3 / Attachment 1 / p. 18

Question(s):

a) Please clarify what is meant by "scalable project delivery method" and comment on its role with the Remaining Units refurbishment and how it differs from and / or improves upon the method previously used.

<u>D2-Staff-134</u>
Exhibit D2 / Tab 2 / Schedule 3 / Attachment 1 / p. 45

Preamble:

OPG noted that Unit 2 experienced delays in receipt of the new feeders due to fabrication backlogs. As a result, all Unit 3 feeders were planned with extra procurement durations and will be received at the station at least 12 months prior to the installation window.

Question(s):

a) Please provide a brief update on the status of Unit 3 feeder receipt.

b) When does the Unit 3 feeder installation window begin?

D2-Staff-135
Exhibit D2 / Tab 2 / Schedule 5 / p. 6

Preamble:

The reference describes changes between the Release Quality Estimate (RQE) / Unit 2 Execution Estimate (U2EE) refurbishment schedule and the final Unit 3 Execution Estimate (U3EE) refurbishment schedule.

Question(s):

a) Please provide a visual or tabular comparison of the RQE / U2EE schedule and the U3EE schedule. Please include an indication of changes to the schedule that resulted from the COVID-19 pandemic.

D2-Staff-136
Exhibit D2 / Tab 2 / Schedule 5 / pp. 14-15

Preamble:

With respect to Unit 3, OPG distinguished among a “High Confidence Schedule” (1,216 days), a “Working Schedule” (1,096 days) and “planned working days” (930 days).

Question(s):

a) Please clarify what “planned working days” means in the above context.

b) How does the number of planned working days differ between the High Confidence Schedule and Working Schedule?

D2-Staff-137
Exhibit D2 / Tab 2 / Schedule 6 / p. 6

Preamble:

OPG stated that the U3EE contingency amount represents approximately 10% of the Remaining Units’ estimate, including contingency. OPG also stated that this percentage is within the range of cost estimate uncertainty associated with a Class 2 estimate per AACE guidelines. Class 2 estimates have a range of -5% to -15% to +5% to +20%.

Question(s):

a) Please advise whether the U3EE is a Class 2 estimate as a whole or that a 10% contingency estimate is consistent with a Class 2 contingency estimate (or both).

D2-Staff-138
Exhibit D2 / Tab 2 / Schedule 6 / p. 4

Preamble:

OPG stated that no amount related to the COVID-19 pandemic was included in the initial contingency developed for the DRP.

Question(s):

a) Does the U3EE include any contingency related to the COVID-19 pandemic? If so, please clarify.

D2-Staff-139
Exhibit D2 / Tab 2 / Schedule 7 / Chart 1

Preamble:

Chart 1 at Exhibit D2 / Tab 2 / Schedule 7 shows that between RQE and U3EE, OPG's cost estimate for Major Work Bundles has increased, its contingency cost estimate has decreased, and its Total High Confidence Estimate has not changed. Reasons include incorporation of lessons learned and reflecting contingency utilized on Unit 2 in base estimates.

Question(s):

a) Please comment on how OPG's lessons learned are translating to savings for ratepayers, given that the total DRP estimate does not change as lessons learned are incorporated.

D2-Staff-140
Exhibit D2 / Tab 2 / Schedule 7 / Chart 1
Exhibit D2 / Tab 2 / Schedule 6 / p. 6

Preamble:

Chart 1 at Exhibit D2 / Tab 2 / Schedule 7 shows an RQE contingency estimate of $2,006 million. OPG stated that the Remaining Units' unspent contingency amount of $647 million is 49% of the $1,312 million that was initially allocated to Units 3, 1, and 4 at RQE.

a) How much of the $2,006 million contingency from RQE was utilized on Unit 2?

b) Does the $647 million contingency estimate in U3EE represent the remainder of the $2,006 million not spent on Unit 2, or does it reflect an updated view of the program and its risks?

D2-Staff-141
Exhibit D2 / Tab 2 / Schedule 7 / pp. 7-8

Preamble:

OPG stated that in its 2017-2021 Payment Amounts Proceeding, the OEB granted envelope approval for OPG's in-service amount request for Unit 2. The reference includes a quote from the OEB's Decision and Order in OPG's 2017-2021 Payment Amounts Proceeding which states, "the refurbishment of Unit 2 is a single integrated project".

The reference also states that based on the final U3EE, and consistent with the OEB's approval for Unit 2 in OPG's 2017-2021 Payment Amount Proceeding, OPG is requesting total in-service additions of $6,442.6 million over the Custom IR term. The in-service additions consist of Remaining Units and some Early-In-Service Projects.

Question(s):

a) In light of the above references, is OPG seeking "envelope approval" for the total remaining cost of completing the DRP or is OPG proposing to treat each Remaining Unit as an individual envelope, akin to how Unit 2 was treated?

b) If Unit 2 was a “single integrated project”, are Units 3, 1 and 4 three separate integrated projects? Or are they together one single integrated project? Please clarify OPG’s proposal.

D2-Staff-142
Exhibit D2 / Tab 2 / Schedule 7 / p. 10

Preamble:

OPG stated that the Unit 3 estimate reflects unit-over-unit productivity improvements of 18%.

Question(s):

a) Please indicate the dollar value of the 18% referenced above.

b) Please indicate the percent and dollar values by which Unit 1 and Unit 4 estimates reflect productivity improvements relative to Unit 2.

D2-Staff-143
Exhibit D2 / Tab 2 / Schedule 7 / Attachment 1 / p. 8
Exhibit D2 / Tab 2 / Schedule 7 / Chart 2

Question(s):

a) Please clarify why the individual unit totals do not match between the two references (i.e. individual unit totals in the second reference are different from those in the first reference).

b) Please provide the RQE version of the 4-unit cost summary set out at Exhibit D2 / Tab 2 / Schedule 7 / Attachment 1 / p. 8.

D2-Staff-144
Exhibit D2 / Tab 2 / Schedule 7 / p. 1
Exhibit D2 / Tab 2 / Schedule 7 / Attachment 1 / p. 4

Preamble:

The first reference above states that the Unit 1 Execution Estimate (U1EE) is forecast to be completed in November 2021 and Unit 4 Execution Estimate (U4EE) is forecast to be completed in May 2023.

The second reference above shows that, according to the High Confidence Schedule (Final U3EE), refurbishment of Unit 1 and Unit 4 is planned to start in February 2022 and September 2023, respectively. According to the same schedule, Unit 3 refurbishment completion is expected in January 2024.

Question(s):

a) What is the general rationale for the timing of U1EE and U4EE? Does OPG anticipate this timing will allow for the incorporation of lessons learned from Unit 3 refurbishment, even though U1EE and U4EE will be issued before Unit 3 refurbishment is complete?

D2-Staff-145
Exhibit D2 / Tab 2 / Schedule 7 / Attachment 3 / pp. 10-11, 27-28

Preamble:

Burns McDonnell / Modus Strategic Solutions stated that CanAtom's Unit 2 performance of the Feeder work yielded the largest cost variance from the base RQE estimate. CanAtom has updated the base estimate for Unit 3 planned production rates, resulting in a 45% increase in direct field labour (DFL) hours over RQE.

Burns McDonnell / Modus Strategic Solutions also stated that the feeder lessons learned examination has only just begun, and until it is complete, there is a risk that CanAtom's Unit 3 estimate could be impacted (reduced or increased). Once the lessons learned process is complete, CanAtom's Unit 3 Feeder plan will require additional vetting to ensure consistency, accuracy and clearly identified changes from Unit 2.

Question(s):

a) With respect to feeder work in particular, to what extent does U3EE reflect the lessons learned process? In OPG's view, was the lessons learned process sufficiently far along at the time of U3EE preparation to provide representative guidance or does OPG expect to develop a restated U3EE to account for the still ongoing nature of the lessons learned process at the time of U3EE preparation?

b) Does the 45% increase in DFL hours over RQE reflect a subset of lessons learned only factors (e.g. workforce scheduling, refinement of crew sizes), or does it encompass the broader set of lessons learned, which include strategic improvements and the Darlington 3 Innovations Project?

c) Please comment on whether / the extent to which the Unit 3 estimates received additional review and vetting based on the completion of the lessons learned.

D2-Staff-146
Exhibit D2 / Tab 2 / Schedule 7 / Attachment 3 / pp. 27-28

Preamble:

Burns McDonnell / Modus Strategic Solutions recommended that "CanAtom should also clearly identify any changes needed from RQE and detail the revised estimate for Units 3/1/4. […] the Feeder program would benefit from a thorough, 360-degree readiness review that vets the Feeder team's ability to avoid and mitigate the issues that impacted Unit 2".

Question(s):

a) Please comment on the status of OPG's response to the recommendations made at the reference above.

D2-Staff-147
Exhibit D2 / Tab 2 / Schedule 7 / Attachment 3 / p. 4

Preamble:

Burns McDonnell / Modus Strategic Solutions recommended that "the DR Team complete the recently started Feeder lessons learned program and provide other means such as partial check estimates and thorough schedule analysis to ensure these estimates are complete."

Question(s):

a) Has OPG undertaken the check estimates and schedule analysis recommended in the reference above? If so, what have been the conclusions and how, if at all, are they reflected in the DRP costs projected by OPG in this application?

D2-Staff-148
Exhibit D2 / Tab 2 / Schedule 7 / Attachment 3 / p. 4

Preamble:

Burns McDonnell / Modus Strategic Solutions stated that "Feeder work was the largest source of increased cost and schedule on Unit 2 and poses a risk to the Unit 3 Control Budget and Schedule. The Unit 2 manhour overrun on the Feeder work was 60% of CanAtom's total manhour overrun on RFR and 35% of the total DR Project overrun."

Question(s):

a) Please outline what, if any, protections for Ontario ratepayers are included in OPG's commercial arrangement with its vendors with respect to potential cost overruns related to feeder work for the Remaining Units.

D2-Staff-149
Exhibit D2 / Tab 2 / Schedule 9 / p. 8
Exhibit D2 / Tab 2 / Schedule 9 / Table 5a

Preamble:

The first reference above states that the actual 2016 in-service amounts of $164.4 million are lower than the OEB-approved amount of $350.4 million.

The second reference shows an actual 2016 in-service amount of $324.4 million.

Question(s):

a) Please reconcile the $164.4 million figure set out in the first reference with the $324.4 million figure shown in the second reference.

Heavy Water Storage and Drum Handling Facility (D2O Storage Project)

D2-Staff-150
Exhibit D2 / Tab 2 / Schedule 10 / pp. 1 and 12
Exhibit D2 / Tab 2 / Schedule 10 / Attachment 2q / p. 5

Preamble:

The first reference states the total cost of the D2O Storage Project is $510 million, consisting of $509.3 million in capital and $0.7 million in OM&A for removal costs incurred in 2013. Of the $509.3 million in capital cost, $14.6 million was placed in service in 2014 and has already been approved for inclusion in rate base and is reflected in the rate base approved in OPG's 2017-2021 Payment Amounts Proceeding. OPG also states that the inclusion of the remaining $494.7 million in OPG's rate base is requested in this application.

The second reference states that the estimate at completion of $498.5 million is the target budget. However, this excludes $11.5 million of management reserve, for a total budget of $510 million.

Question(s):

a) Please confirm the total capital cost of the D2O Storage Project: is it $509.3 million?

b) Please confirm the total D2O Storage Project cost including removal costs of $0.7 million in OM&A incurred in 2013: is it $510 million?

c) Does the $498.5 million cited in the second reference include both capital and OM&A costs or just capital costs?

d) Does the $510 million cited in the second reference include both capital and OM&A costs or just capital costs?

e) What is "management reserve" and where does its funding come from?

f) How much, if any, management reserve was released for the D2O Storage Project?

g) Is OPG seeking to recover the cost of any management reserve for the D2O Storage Project as part of this application? If so, how much? If not, please clarify.

D2-Staff-151

Exhibit D2 / Tab 2 / Schedule 10 / Attachment 2q / pp. 2-3

Preamble:

OEB staff adapted the following table based on the scanned document provided at the above reference.

Question(s):

a) Please confirm the accuracy of OEB staff's adapted table below.

	Date	Total Cost with Contingency ($k)
Developmental Release	November 2006	36,863
Full Definition Release	June 2012	108,148
Partial Execution Release	August 2012	108,051
Full Execution Release	May 2013	110,015
Superseding Full Execution Release	March 2015	381,100
Superseding Full Execution Release	January 2018	498,500

b) For each release, starting with the Full Definition Release dated June 2012, please briefly outline key changes in project scope and / or design from the previous release.

c) For each release, starting with the Developmental Release, please indicate the corresponding estimate of Project Close-out Complete date.

D2-Staff-152

Exhibit D2 / Tab 2 / Schedule 10 / p. 44

Preamble:

OPG stated that it had done sampling following a 2009 spill at the Injection Water Storage Tank, which indicated elevated tritium levels in the soil and groundwater in the area north of the site.

Sampling within the footprint of the D2O Storage Project construction showed that the tritium levels observed, while above background levels, did not exceed Ministry of the Environment standards.

Question(s):

a) Please clarify the approximate date referenced in the first quote above (i.e. month and year) when OPG had done sampling following a 2009 spill.

b) Please clarify the approximate date by which the sampling results were available to OPG.

D2-Staff-153
Exhibit D2 / Tab 2 / Schedule 10 / p. 53

Preamble:

OPG stated that at the time of the request for proposals (RFP), it was still investigating potential soil contamination issues.

Question(s):

a) Please clarify the approximate date of the RFP referenced in the quote above.

D2-Staff-154
Exhibit D2 / Tab 2 / Schedule 10 / Attachment 2q / pp. 2-3

Preamble:

OPG stated that the low concentration of tritium was from a spill in 2009 and eliminated the option of disposing of this soil conventionally. While the concentrations were below regulatory limits, the soil had to be treated to address the tritium before it can be removed from the Darlington NGS site. OPG stated that this was a large contributor to added costs to the project.

Question(s):

a) Please explain why OPG had to treat the soil even though its concentrations were below regulatory limits.

D2-Staff-155
Exhibit D2 / Tab 2 / Schedule 10 / p. 53
Exhibit D2 / Tab 2 / Schedule 10 / Attachment 2q / p. 3

Preamble:

OPG stated that the RFP for the D2O Storage Project instructed the proponents to assume that the project would involve uncontaminated soil that could be disposed of in a conventional landfill.

OPG also stated that soil testing revealed low levels of tritium in some of the soil. The presence of low levels of tritium above the free release limits of the Darlington license required ongoing testing and that the excavated soil be placed in a laydown area so any remaining tritium could dissipate prior to permanent soil disposal.

OPG also stated that to create a lay down area to accommodate the soil and bedrock generated by the project, OPG increased the scope of its purchase order with its contractor to construct the soil lay down area.

Question(s):

a) Why did OPG ask proponents to assume that the project would involve uncontaminated soil given knowledge of the spill in 2009?

b) Please clarify the difference or similarity between the criterion of "free release limits" and "regulatory limits".

D2-Staff-156
Exhibit D2 / Tab 2 / Schedule 10 / Attachment 2q / p. 3

Preamble:

OPG stated that additional water treatment equipment was also required to lower the ground water table and allow excavation during the site preparation phase while meeting environmental discharge limits.

Question(s):

a) Please clarify whether the need for additional water treatment equipment was related to the soil contamination.

D2-Staff-157
Exhibit D2 / Tab 2 / Schedule 10 / pp. 65-69, 93, 112

Question(s):

a) What was the nature of OPG's management / oversight function for the D2O Storage Project with regard to Black and McDonald (B&M)?

b) What was the nature of OPG's management / oversight function for the D2O Storage Project with regard to CanAtom? Did it differ from OPG's role with B&M?

c) In both cases, what was the involvement of OPG's P&M organization?

D2-Staff-158
Exhibit D2 / Tab 2 / Schedule 10 / p. 106

Preamble:

OPG stated that the Pickering D2O storage project installed four 90 m^3 tanks in an existing building with existing support services. This project was initially estimated to cost $11.2 million. The project was delayed 18 months and ultimately cost $16.3 million.

OPG also stated that the Bruce D2O project installed six 135 m^3 tanks in an existing building with existing support services. This project was initially estimated to cost $13 million. At the time that the estimate for the 2011 Draft Developmental BCS was being prepared, the Bruce project was still ongoing, but it was anticipated to cost $40 million and had experienced years of delay because it had been placed on hold for 18 months.

Question(s):

a) How would OPG characterize the size and complexity of the Darlington D2O storage facility relative to that of the Pickering and Bruce D2O storage facilities cited in the reference above? How much larger and more (or less) complex is it?

b) Who (i.e. which organization) developed the initial scope, cost and schedule estimates for the D2O Storage Project? Was it the same organization that developed the estimates for the Pickering and Bruce storage projects?

c) On what basis were the initial scope, cost and schedule estimates for the D2O Storage Project developed?

d) How was the experience / lessons learned of the Pickering and Bruce D2O storage facilities reflected in the Darlington D2O Storage Project's estimates?

D2-Staff-159
Exhibit D2 / Tab 2 / Schedule 10 / p. 106

Preamble:

OPG stated that early estimates of project cost and schedule were understated.

Question(s):

a) Please confirm how over-schedule the D2O Storage Project was at completion?

b) In OPG's analysis, did the project take more time and money to complete than it would have otherwise taken if the full scope of the project was reflected in early estimates, such as in the Developmental Release? If so, by how much? if not, why not?

D2-Staff-160
Exhibit D2 / Tab 2 / Schedule 10 / p. 110

Preamble:

OPG discusses construction costs increases due to changes from a "preliminary design" to a "final design" for the D2O Storage Project.

Question(s):

a) Please confirm the approximate date of the preliminary design and final design.

D2-Staff-161
Exhibit D2 / Tab 2 / Schedule 10 / p. 110

Preamble:

OPG stated that as with the 2015 Superseding Release Execution BCS, the 2018 Superseding Release Execution BCS analyzed the variances that led to increased project costs. OPG mentioned “increased project scope” and “underestimation of cost” as being among the most important contributors to cost increases.

Question(s):

a) Please develop a table which compares the final D2O Storage Project cost with the Developmental Release estimate and that broadly summarizes the sources of cost increases between the two according to categories readily available to OPG based in its prior analysis of variances that led to increases in project costs (i.e. increased project scope, underestimation of cost, etc.). If OPG considers it more appropriate, please create a different version of the above table comparing the final D2O Storage Project cost with the Full Definition Release (i.e. instead of the Developmental Release).

D2-Staff-162
Exhibit D2 / Tab 2 / Schedule 10 / p. 112
Exhibit D2 / Tab 2 / Schedule 10 / Attachment 2q / p. 3

Preamble:

OPG stated that by the time that it terminated the agreement with the original vendor, the cost and schedule to deliver the facility was substantially higher than originally anticipated.

OPG identified major cost contributors at this stage of the project which include soil contamination, standalone structure and structural changes, permanent material requirements and field work for site preparations / ground water elevation.

Question(s):

a) Please confirm that B&M is the initial contractor referenced above and that OPG terminated B&M’s D2O Storage Project contract on October 16, 2014. Otherwise, please clarify.

b) Please summarize how much was spent on the D2O Storage Project, including capital and OM&A, up to the point when OPG terminated the contract with the initial contractor.

c) Please summarize the contribution of each of the major cost contributors described at the above reference to the higher than originally anticipated cost and schedule. In the response, please specifically discuss the impact of the soil lay down area and additional water treatment.

D2-Staff-163
Exhibit D2 / Tab 2 / Schedule 10 / Attachment 2q / p. 9

Question(s):

a) The table at the top of the page at the above reference has a column heading called “Original 3b Target Date”. Does that refer to the Developmental Release of 2006, the Full Definition Release of 2012, or something else? Please clarify.

b) The same table has a column heading called “Current BCS Target Date”. Does that refer to the Superseding Full Execution Release of January 2018? Please clarify.

c) Please confirm that the deliverables marked with the term “New Milestone” were not included in the “Original 3b BCS.” If this is not correct, please explain.

d) Please add a column to the right of the table which shows the month and year of actual completion of each of the deliverables.

D2-Staff-164
Exhibit D2 / Tab 2 / Schedule 10 / Attachment 2q

Question(s):

a) Please confirm the date of the document (Type 3 Business Case Summary) at the above reference.

D2-Staff-165
Exhibit D2 / Tab 2 / Schedule 10 / Attachment 2a / p. 13

Preamble:

The Project Charter includes a cover page for Appendix A but does not include Appendix A itself.

Question(s):

a) Please file Appendix A to the Project Charter ("Appendix A: Strategic Options Study for OPG Heavy Water Storage and Handling").

Bates White – D2O Construction Cost Study

D2-Staff-166
Exhibit D2 / Tab 2 / Schedule 11 / Attachment 3

Question(s):

a) Please advise whether Bates White Economic Consulting (Bates White) has ever completed a cost estimate of a similar nature to the one filed in the current proceeding (i.e. estimating the cost of a project after it has been completed assuming "perfect knowledge"). If so, please provide references to those studies and advise if those studies were ever filed for regulatory / legal purposes.

D2-Staff-167
Exhibit D2 / Tab 2 / Schedule 11 / Attachment 3 / p. 5
Exhibit D2 / Tab 2 / Schedule 10 / Attachment 2q

Preamble:

Bates White concluded that the estimated total cost of the D2O Storage Project, based on perfect knowledge, is $517.7 million.

Bates White's Class 2 estimate is accurate within 15% above and 10% below the expected cost for the D2O Storage Project of $517.7 million. On a P90 basis, Bates White's estimate of the D2O Storage Project is $576.5 million.

Question(s):

a) For clarity, is the $517.7 million Bates White estimate a Class 2 estimate?

b) Does the $576.5 million P90 estimate refer to a P90 of a Class 2 estimate?

c) What class of estimate was OPG's Superseding Full Execution Release?

d) Did the $498.5 million Superseding Full Execution Release reflect a mean estimate? If not, please explain.

e) What is the P90 value of OPG's Superseding Full Execution Release?

D2-Staff-168
Exhibit D2 / Tab 2 / Schedule 11 / Attachment 3 / p. 14

Preamble:

Bates White stated that its construction cost estimate for the D2O Storage Project is $517.7 million, based on a six-year construction timeline commencing in 2013 and ending in 2018, followed by commissioning and close-out.

Question(s):

a) Please clarify how the construction timeline above compares with OPG's actual construction timeline for the D2O Storage Project.

D2-Staff-169
Exhibit D2 / Tab 2 / Schedule 11 / Attachment 3 / Table 5 / p. 15

Question(s):

a) Please add a column to Table 5 at Exhibit D2 / Tab 2 / Schedule 11 / Attachment 3 / p. 15 that summarizes OPG's actual costs using the same categories.

D2-Staff-170
Exhibit D2 / Tab 2 / Schedule 11 / Attachment 3 / pp. 19

Preamble:

Bates White noted that the initial estimate of overnight direct costs is $377.2 million. This initial estimate incorporates amounts, identified directly on vendor invoices and purchase orders and inferred by RSMeans, to cover the EPC contractor's overhead and profit. Bates White removed the inferred amounts in calculating the estimate of the 2019 overnight costs for the Bill of Quantities (BOQ) items.

Question(s):

a) Please advise whether the $377.2 million initial estimate of overnight direct costs includes: (i) contingency; (ii) overhead; and (iii) profit. If it does not include contingency, please explain why.

b) Please confirm that the inferred amount that was removed from the initial estimate of overnight direct costs is $34.3 million.

c) Please provide the "then-year" costs using the $377.2 million initial estimate of overnight direct costs (prior to removing the inferred costs).

D2-Staff-171
Exhibit D2 / Tab 2 / Schedule 11 / Attachment 3 / pp. 17, 56

Preamble:

Bates White noted that the labour costs in the RSMeans database are based on a standard 5-day, 8 hour per day workweek with no overtime. The D2O Storage Project construction workers are on a 4-day, 10 hour per-day workweek schedule, with 2 hours a day of overtime.

Bates White also noted that actual average hourly rates for OPG contractors were higher than the labour rates embedded in RSMeans for the Toronto metropolitan area. To determine how much higher, Bates White computed the ratio of actual OPG contractor wage rates for various trades (e.g. electrician journeyman, structural steel foreman, and plumber) to RSMeans wage rates for the same trades at comparable seniority levels. Bates White obtained the OPG contractor rates from a Canadian government source and factored in 2 hours' worth of overtime pay daily to account for the contractor's 10-hour day. Bates White found that the contractor's average labour rate was, on average, 1.46 times higher than the RSMeans presumed labour cost. In other words, if RSMeans reported a CAD $50 per hour wage rate, the commensurate actual wage rate was CAD $73 per hour.

Question(s):

a) Please advise whether D2O Storage Project workers were on a 4-day, 10 hour per day (with 2 hours of overtime) schedule throughout the entire duration of the D2O Storage Project. If not, please explain how this was reflected in the labour cost adjustment.

b) Please explain why D2O Storage Project workers were on a 4-day, 10 hour workday (with 2 hours of overtime). Please provide rationale supporting the necessity for OPG to pay the costs associated with 2-hours of overtime every day that was worked.

c) Please confirm that the 1.46 labour cost factor includes both the wage differential and the cost of overtime.

<u>D2-Staff-172</u>
Exhibit D2 / Tab 2 / Schedule 11 / Attachment 3 / pp. 17, 56-59
Exhibit D2 / Tab 2 / Schedule 11 / Attachment 3 / p. 15 / Table 5

Preamble:

Bates White found that an average 39% productivity factor would be appropriate for the D2O Storage Project.

Question(s):

a) Please advise which categories of costs in Table 5 at Exhibit D2 / Tab 2 / Schedule 11 / Attachment 3 / p. 5 are impacted by the assumed productivity factor.

b) Does the term "average productivity factor" denote an average of different cost categories or an average over some period of time, or both?

c) Please produce a sensitivity plot or table which shows the impact of different average productivity factors (between 39% and 66%) on Bates White's $517.7

million total project cost estimate. Please produce the sensitivity plot at 1% increments, whether individually calculated or interpolated.

d) Based on the sensitivity plot above, please indicate what a 1% increase in productivity factor would equate to in terms of overall project cost impact relative to Bates White's $517.7 million total project cost estimate (e.g. project cost changes by $x for every 1% increase in productivity factor). If the impact is non-linear, please clarify.

e) Please provide the average productivity factor that OPG uses for DRP Unit refurbishments per U3EE. Does U3EE assume an average 39% productivity factor?

f) Please provide the average productivity factor that OPG uses for developing its operations and maintenance budgets. Do these budgets assume an average 39% productivity factor?

D2-Staff-173
Exhibit D2 / Tab 2 / Schedule 11 / Attachment 3 / pp. 56-59

Preamble:

Bates White multiplied the 1.7 factor for the productivity adjustment by the wage factor adjustment of 1.46 to derive a combined factor of 2.5.

Bates White noted that the RSMeans database does not contain data that is applicable for procuring or installing materials required to meet nuclear quality standards. Thus, for those items in the BOQ requiring nuclear quality assurance, Bates White supplemented the RSMeans data with additional crew members (welders and quality assurance specialists) and adjusted for specialized material and labour costs based on cost factors in the EMWG guidelines.

Question(s):

a) Please confirm that the 2.5 combined productivity and wage was applied on top of the EMWG factor for those categories of costs requiring nuclear quality assurance.

b) Using SS Pipe > 50mm as an example (Table C-6 at Exhibit D2 / Tab 2 / Schedule 11 / Attachment 3 / p. 58) and assuming a $100 RSMeans Labour cost, OEB staff has attempted to derive the formula and calculation that would apply for the EMWG and combined labour wage and productivity adjustment:

(1) RSMeans average wage rate x RSMeans hours = RSMeans Cost
(2) RSMeans Cost * EMWG Factor = EMWG Cost
(3) EMWG Cost + RSMeans Cost = "Initial Cost" (before 2.5x Combined Wage and Productivity Factor)
(4) Initial Cost * 2.5 (combined Wage and Productivity Factor) = Bates White Cost

(1) $100 x 1.54 = $154 (RSMeans Cost)
(2) $154 (RSMeans Cost) x 55.73 (EMWG Factor) = $8,582.4 (EMWG Cost)
(3) $154 (RSMeans Cost) + $8,582.4 (EMWG Cost) = $8,736.4 (Initial Cost)
(4) $8,736.4 (Initial Cost) * 2.5 (combined Wage and Productivity Factor) = $21,841 (Bates White Cost)

Please confirm or revise the above as necessary to reflect Bates White's calculation for the combined EMWG and labour wage / productivity adjustment factor (2.5) (in the context of the provided scenario).

c) Please add to the above calculation any further adjustments for crew size.

d) Please provide the total cost that added crew members reflect in the total project cost of $517.7 million.

D2-Staff-174

Exhibit D2 / Tab 2 / Schedule 11 / Attachment 3 / pp. 58-60

Preamble:

Bates White noted that it derived its estimate for the OPG contractor productivity from data in two "wrench time" studies that were commissioned by OPG that are consistent with Bates White's own first-hand experience with construction projects inside the protected area of a nuclear facility.

The "wrench time" study done by the University of Ontario Institute of Technology reviewed several DRP activities to identify major contributors to downtime which were divided into two categories: site specific considerations (i.e. breaks, briefings, site preparation, travel time, waiting, work stoppage) and items common among nuclear facilities (i.e. personal protective equipment, permit sign-off, activity tooling and equipment).

Bates White noted that the EMWG guidelines do not present specific information regarding assumptions upon which it based its labour rate projections. However, Bates White is of the view that the EMWG are mean estimates and more likely to be consistent with RSMeans-type productivity assumptions than the data-driven factors determined by the available site-specific “wrench time” studies. Bates White stated that as the EMWG productivity factors are mean estimates, combining the reduced wrench time productivity estimate with the EMWG installation rate data is a reasonable approach and should produce reliable results.

Question(s):

a) Please advise what aspects of the DRP were the subject of the “wrench time” studies.

b) Please advise whether it is Bates Whites position that:

   i. The EMWG nuclear unit hours and non-nuclear unit hours reflect none of the site-specific considerations and therefore combining the reduced wrench time productivity estimate and EMWG data is appropriate; or

   ii. OPG’s D2O Project had greater downtime for the noted site-specific considerations than what is reflected in the EMWG nuclear unit hours and non-nuclear unit hours and therefore combining the reduced wrench time productivity estimate and EMWG data is appropriate.

c) Please discuss in detail Bates White’s understanding of how the nuclear unit hours and non-nuclear unit hours were derived for the EMWG guidelines. Specifically, please advise whether the unit hours in the EMWG guidelines are based on averages of actual construction times for nuclear construction projects.

d) Please provide the total project cost (comparable to the $517.7 million estimate) if the labour productivity adjustment was not applied in combination with the EMWG-related factors (i.e. applying only the EMWG factor and wage adjustment to the relevant categories of labour costs).

D2-Staff-175
Exhibit D2 / Tab 2 / Schedule 11 / Attachment 3 / pp. 62-64

Preamble:

Bates White provided an example of its calculation of an EPC Contractor final cost for vendor procured items.

Question(s):

a) Please explain the interaction, if any, between Bates White's EPC Contractor final cost calculation with: (i) the combined labour productivity / wage adjustment; and (ii) the EMWG adjustment factor.

Exhibit D3 – Corporate Support Services Capital

D3-Staff-176
Exhibit D3 / Tab 1 / Schedule 1 / p. 9

Preamble:

OPG discussed its real estate strategy, which is primarily based on constructing the new Clarington Corporate Campus to consolidate non-plant employees at one principal location, and moving away from a lease strategy. OPG estimated that this strategy will result in a reduction of approximately $65 million over the next 40 years.

Question(s):

a) Please provide a discussion regarding whether OPG has reconsidered the need (or size) of the Corporate Campus building in the context of the work from home provisions that OPG implemented during the COVID-19 pandemic.

b) Please advise whether the Corporate Campus building is intended to serve only an administrative function (i.e. there will not be workshops, garages, etc. in the building).

c) Please provide the following related to the Corporate Campus building:

    i. $ / Sq. Ft.

    ii. $ / FTE (only include FTE’s that will work full-time, or near full-time, at the Corporate Campus building).

d) Please explain in detail how OPG arrived at a $65 million reduction in costs, including the assumptions related to the cost of leasing over a 40-year timeframe.

D3-Staff-177
Exhibit D3 / Tab 1 / Schedule 2 / Tables 5a-5b

Question(s):

a) Please provide a breakdown of the aggregate 2017-2021 support services capital in-service additions (both planned and actual) recovered through: (i) rate base; and (ii) asset service fees.

b) Please provide a breakdown of the aggregate 2022-2026 support services capital in-service additions (both planned and actual) recovered through: (i) rate base; and (ii) asset service fees.

c) As part of this response, please discuss how minor fixed assets are recovered (i.e. rate base or asset service fees).

D3-Staff-178
Exhibit D3 / Tab 1 / Schedule 2 / p. 6

Preamble:

OPG identified two separate capital projects related to the “Reimagine Program” which appears to be two phases of the same project. OPG stated that the cost of the “Reimagine Program”, which was completed in 2020, is $17.5 million. “Reimagine Program 2.0” was started in the same year (2020) and is estimated to cost $14 million. The total cost of the “Reimagine Program” is therefore estimated to be $31.5 million.

Question(s):

a) Is OEB staff’s understanding correct that this was a phased project and the total cost related to the “Reimagine Program” project is over $30 million? If so, was a BCS completed? If a BCS was completed, please provide it. If a BCS was not completed, please explain why.

D3-Staff-179
Exhibit D3 / Tab 1 / Schedule 2 / p. 8

Preamble:

OPG identified a new capital project referred to as the "Pickering Wi-Fi Power House Unit 1-8" which would establish a broadband wireless network infrastructure within the station to "facilitate direct access to the data and applications required to perform field work." OPG also noted that the project is expected to be completed in 2023 at a cost of $18.3 million. OPG further discussed a project related to Darlington (the Darlington Wireless Program) that also involves establishing network to "facilitate direct access to data and applications required to perform field work" and it has an estimated cost of $6.4 million.

Question(s):

a) When in 2023 does OPG forecast that the Pickering Wi-Fi Power House Unit 1-8 project will be completed?

b) Please explain why the Pickering Wi-Fi Power House Unit 1-8 project is needed with Pickering NGS going out of service in 2025.

c) Would OPG's staff have access to the data and applications required to perform field work without the Pickering Wi-Fi Power House Unit 1-8 project? If not, please explain how OPG's staff are currently accessing the data and applications required without it.

d) Please explain why the cost of the wireless project at Pickering NGS is expected to be almost three-fold higher than the wireless project at Darlington NGS where both are being undertaken to achieve the same purpose.

Exhibit E2 – Nuclear Production Forecast

E2-Staff-180
Exhibit E2 / Tab 1 / Schedule 1 / Table 1

Preamble:

The table at the above reference presents annual nuclear production between 2016 and 2019 and forecast annual nuclear production between 2020 and 2026 at a station-specific level (Darlington NGS total and Pickering NGS total).

Question(s):

a) Please provide the information in the table above at a unit-specific level.

b) Please provide the actual 2019 and 2020 production amounts (TWh) for the hydroelectric facilities and the relative percentage of electricity produced by the nuclear and hydroelectric generating stations.

E2-Staff-181
Exhibit E2 / Tab 1 / Schedule 1 / pp. 3, 8

Preamble:

OPG referenced improvements to outage execution performance and removal of scope from planned outages between 2017 and 2019.

OPG stated that the planned outage schedule incorporates lessons learned from past OPG outages and operating experience outside of OPG.

Question(s):

a) Please clarify how the impact of recent improvements to outage execution performance is reflected in OPG's nuclear production forecast to 2026.

b) Please clarify any further improvements anticipated and how they are reflected in OPG's nuclear production forecasts to 2026.

c) Please provide key examples of how the planned outage schedule incorporates lessons learned from past OPG outages and operating experience outside of OPG.

d) Please provide a tabular summary of trends in planned outage frequency and duration between 2016 and 2020 and comment on how these trends compare to OPG's forecasts to 2026. Please discuss whether the planned outage frequency and average duration are expected to increase, decrease or remain approximately the same and explain why.

E2-Staff-182
Exhibit E2 / Tab 1 / Schedule 1 / pp. 4-5
Exhibit F2 / Tab 4 / Schedule 1 / p. 9

Preamble:

OPG provided examples of unbudgeted planned outages at Pickering NGS and Darlington NGS between 2017 and 2020 and identified the duration of those outages.

Question(s):

a) Please provide a table that presents total unbudgeted planned outage days and associated production losses for each year between 2016 and 2020 at each of Pickering NGS and Darlington NGS.

b) Please confirm that unbudgeted planned outages are not included in the proposed 2022-2026 revenue requirement.

E2-Staff-183
Exhibit E2 / Tab 1 / Schedule 1 / p. 6

Preamble:

OPG stated that the extended operation of Units 1 and 4 from 2022 to 2024 results in 202.8 additional planned outage days and that the extended operation of Units 5-8 from 2024 to 2025 results in an additional 100.8 days at Unit 5.

Question(s):

a) Please estimate the production loss associated with these additional outage days.

b) Please estimate the estimated production gain associated with extended operation of Units 1 and 4 from 2022 to 2024 and extended operation of Units 5-8 from 2024 to 2025. How does the production gain compare to the production loss required to achieve it?

E2-Staff-184
Exhibit E2 / Tab 1 / Schedule 1 / p. 6

Preamble:

OPG's proposed planned derates at Pickering NGS, which will allow additional online maintenance time to address a major contributor to station forced loss rate (FLR).

Question(s):

a) Please clarify how the planned derates allow for additional online maintenance.

b) Please clarify the connection between fuel handling equipment performance and Pickering NGS reliability.

c) How have the planned derates been reflected in OPG's FLR forecast for Pickering NGS (i.e. has the FLR forecast been reduced as a result and by how much)?

E2-Staff-185
Exhibit E2 / Tab 1 / Schedule 1 / p. 14

Preamble:

OPG's projected FLR for Darlington NGS units returning to service after refurbishment is 12.0% for the first year, 6.0% for the second year, 2.0% for the third year and returning to the 1.0% target thereafter. OPG stated that this three-year FLR schedule is based on industry operating experience.

Question(s):

a) What was the FLR of Darlington NGS Unit 2 in its first year or year-to-date following refurbishment outage? How many outage days was that FLR equivalent to?

b) Please provide FLR statistics from industry operating experience that support OPG's projected three-year FLR schedule for Darlington NGS units returning from refurbishment outage.

c) How many outage days will OPG's three-year FLR schedule equate to for Units 1,3 and 4 in each applicable year? How does this compare to the outage days associated with OPG's longer-term 1% FLR target for Darlington NGS?

E2-Staff-186
Exhibit E2 / Tab 1 / Schedule 2 / p. 8
Exhibit E2 / Tab 1 / Schedule 2 / Tables 1a and 1b

Preamble:

OPG stated that the 2020 Budget reflects a 3.5% FLR target at Pickering NGS, whereas the 2019 actual FLR was 1.6%.

Based on the data presented in Table 1a at Exhibit E2 / Tab 1 / Schedule 2, OEB staff calculates that between 2016 and 2020, Pickering NGS's actual cumulative FLR days equivalent was approximately 16.3% lower (96 days equivalent) than approved / budgeted (including the 2020 budgeted value).

Question(s):

a) Please explain why OPG proposed a 3.5% Pickering NGS FLR in its production forecast for the 2022-2026 Custom IR term given that 3.5% would represent a near doubling of the 2019 actual FLR and given that OPG has generally tended to over forecast the Pickering NGS FLR in recent years.

E2-Staff-187
Exhibit E2 / Tab 1 / Schedule 1 / p. 5

Preamble:

OPG stated that in response to the COVID-19 pandemic, OPG revised the schedule for the DRP by deferring the Unit 3 refurbishment outage to start in September 2020, to be followed by Unit 1 in 2022, and Unit 4 in 2023.

Question(s):

a) For the period 2020 through 2026, please provide a table which shows: (i) annual Darlington NGS production per the revised DRP schedule developed by OPG in response to the COVID-19 pandemic; (ii) annual OEB-approved production amounts for 2020 and 2021, and previously forecasted production for the years 2022 through 2026 (i.e. forecasted by OPG before it revised the DRP schedule in response to the COVID-19 pandemic); and (iii) differences between (i) and (ii).

b) If changes were also made to OPG's Pickering NGS production forecast as a result of the COVID-19 pandemic, please also develop a similar table for Pickering NGS. Otherwise, please confirm that OPG's production forecast for Pickering NGS was unaffected by the COVID-19 pandemic.

E2-Staff-188
Exhibit E2 / Tab 1 / Schedule 1

Question(s):

a) For each year between 2020 and 2026, please prepare a table such as the one below that shows monthly Refurb PO Days for each Darlington NGS unit. Please also show monthly totals.

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2020	U2 Refurb PO Days													
	U3 Refurb PO Days													
	U4 Refurb PO Days													
	U1 Refurb PO Days													
	Total Darlington Refurb PO Days													

b) For each year between 2020 and 2026, please prepare a table such as the one below that shows monthly production for each Darlington NGS unit. Please also show monthly totals.

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2020	U2 GWh													
	U3 GWh													
	U4 GWh													
	U1 GWh													
	Total Darlington GWh													

E2-Staff-189

Exhibit E2 / Tab 1 / Schedule 1 / p. 10

Preamble:

OPG stated that Darlington NGS Unit 2 will have a 190.1 day planned outage in 2025 to install turbine generator controls. OPG stated that the installation of turbine generator controls was excluded from Unit 2 refurbishment scope to mitigate risk.

Question(s):

a) Please comment on why OPG proposed the 190.1 day planned outage in 2025. How is the timing of this outage coordinated with OPG's nuclear production optimization efforts?

b) Please estimate the production loss associated with this outage.

E2-Staff-190
Exhibit E2 / Tab 1 / Schedule 1 / pp. 11-12

OPG noted that it plans to take a Pickering Vacuum Building Outage (VBO) in 2022. OPG stated that it is investigating the use of technology that, subject to CSNC approval, may allow OPG to reduce the duration of the planned 2022 VBO.

OPG noted that it expects to seek the CNSC's approval in the first quarter of 2021. OPG stated that it will update its application should there be any resulting material change related to the 2022 VBO. Absent CNSC approval, OPG must plan to execute the 2022 VBO over the currently scheduled duration.

Question(s):

a) Please estimate the production loss associated with the planned 2022 VBO.

b) Please estimate the likely impact of the technology referenced above, if approved by CNSC, on the duration and production loss of the 2022 VBO.

c) Please provide an update on the CNSC approval and discuss whether OPG expects to update its application to reflect a shorter 2022 VBO. Please discuss the potential timing of this update.

E2-Staff-191
Exhibit E2 / Tab 1 / Schedule 1 / p. 12

Question(s):

a) Please provide a tabular summary of trends in production losses per forced outage between 2016 and 2020 and comment on how these trends compare to OPG's forecasts to 2026. Please discuss whether production losses per forced outage are expected to increase, decrease or remain approximately the same and explain why.

E2-Staff-192
Exhibit E2 / Tab 1 / Schedule 2 / Tables 1a and 1b

Preamble:

Based on the data presented in the referenced tables, OEB staff calculated that between 2017 and 2021, OPG's actual cumulative nuclear production was, in total, approximately 17 TWh (9%) higher than approved / budgeted (including the 2021 budgeted value), as shown below:

Row No.		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	Darlington:	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**Total 2017-2021**
1	**OEB Approved 2017-2021, Budget 2016**	26.0	19.0	19.3	19.7	17.7	16.6	92.3
2	**Actual 2016 -2019, Budget 2020-2021**	25.6	19.3	20.0	19.9	21.8	16.9	97.9
3	**Difference (2 minus 1)**	-0.4	0.3	0.7	0.2	4.1	0.3	5.6
	Pickering:	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**Total 2017-2021**
4	**OEB Approved 2017-2021, Budget 2016**	20.8	19.1	19.2	19.4	19.6	18.8	96.1
5	**Actual 2016-2019, Budget 2020-2021**	19.9	21.4	20.9	23.6	20.3	21.4	107.6
6	**Difference (5 minus 4)**	-0.9	2.3	1.7	4.2	0.7	2.6	11.5
	Total	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**Total 2017-2021**
7	**OEB Approved 2017-2021, Budget 2016**	46.8	38.1	38.5	39.0	37.4	35.4	188.4
8	**Actual 2016 -2019, Budget 2020-2021**	45.6	40.7	40.9	43.5	42.0	38.3	205.4
9	**Difference (8 minus 7)**	-1.2	2.6	2.4	4.5	4.6	2.9	17.0

Question(s):

a) Please confirm the accuracy of OEB staff's table above. If OEB staff's table is incorrect, please provide a corrected version.

Exhibit F – Operating Costs

Exhibit F2 – Nuclear Operating Costs

Nuclear Benchmarking Summary

F2-Staff-193
Ref: Exhibit F2 / Tab 1 / Schedule 1 / p. 4

Question(s):

a) Please comment on OPG's reliability performance when evaluated using measures of Critical Deficiencies (i.e. 1-year On-Line Deficient Critical Maintenance Backlogs and 1-year On-Line Corrective Maintenance Backlogs). In the response, please discuss whether OPG achieves a better performance when considering measures of Critical Deficiencies exclusively.

F2-Staff-194
Exhibit F2 / Tab 1 / Schedule 1 / p. 5

Preamble:

OPG noted that it has included several normalization adjustments to the value for money metrics. These adjustments normalize for Darlington NGS refurbishment costs, CANDU technology and age-related impacts.

Question(s):

a) Please discuss whether OPG expects to continue applying any of the noted normalization adjustments in 2027 after the completion of the Pickering NGS shutdown and the DRP.

F2-Staff-195
Exhibit F2 / Tab 1 / Schedule 1 / p. 9 / Chart 1

Preamble:

OPG provided the following chart that highlights the impact of the normalizations applied to the value for money metrics.

Indicator	Non-Normalized	Refurbishment Normalization	CANDU and age-related Normalization	Combined Normalization
3-year Total Generation Cost per MWh	PN: $62.39 DN: $67.00	PN: N/A DN: $54.18	PN: $44.85 DN: $50.99	PN: $44.85 DN:$38.84
3-year Total Generating Cost per Unit	PN: $228.27 DN: $442.14	PN: N/A DN: $357.53	PN: $176.31 DN: $355.07	PN: $176.31 DN: $270.46
3-Year Non-Fuel Operating Cost per MWh	PN: $53.85 DN: $47.10	PN: N/A DN: $37.85	N/A	N/A
3-year Capital Cost per MW DER	PN: $30.66 DN: $116.67	PN: N/A DN: $89.78	N/A	N/A

Question(s):

a) Please confirm that there are three adjustments that form part of the CANDU and age-related normalization (technology, age and outages).

b) Please expand Chart 1 at Exhibit F2 / Tab 1 / Schedule 1 / p. 9 to include the impact of each of the three CANDU and age-related normalization on three-year TGC / MWh shown separately.

c) Please file alternative versions of Chart 1 at Exhibit F2 / Tab 1 / Schedule 1 / p. 9 that show the impact of each normalization (refurbishment and each of the CANDU and age-related normalizations) on the first, second and third quartile performance indicators.[16]

d) Please provide the same expanded chart as requested in parts (b) and (c) for 2017 and 2018.

[16] The referenced quartile-based performance indicators are shown in Exhibit F2 / Tab 1 / Schedule 1 / Attachment 5 / p. 4 (as an example).

Target Setting

F2-Staff-196
Exhibit F2 / Tab 1 / Schedule 1 / pp. 16-17
Exhibit F2 / Tab 1 / Schedule 1 / Attachment 2 / p. 6
Exhibit F2 / Tab 1 / Schedule 1 / Attachment 3 / p. 10

Preamble:

OPG provided annual operational and financial targets for Pickering and Darlington in Charts 3 and 4 at Exhibit F2 / Tab 1 / Schedule 1 / pp. 16-17.

The ScottMadden Evaluation of 2019 OPG Nuclear Benchmarking states that OPG has informed ScottMadden that during the 2020 business planning cycle, OPG plans to use three-year rolling average targets and normalized three-year rolling average targets for value for money metrics. The change is intended to better align with the metrics themselves, which are calculated as three-year rolling averages, and to reduce year-to-year volatility associated with refurbishment operations. OPG will also continue to set one-year targets.

Question(s):

a) Please further explain the statement in Note 4 at Exhibit F2 / Tab 1 / Schedule 1 / pp. 16-17 that the value for money targets are indicative and will be updated for final cost allocations reflected in the application.

b) Please advise whether the 2020-2026 targets provided in Charts 3 and 4 at Exhibit F2 / Tab 1 / Schedule 1 / pp. 16-17 are three-year rolling average targets or annual targets.

c) Please provide the same information as provided in Charts 3 and 4 at Exhibit F2 / Tab 1 / Schedule 1 / pp. 16-17 for the period 2013-2020. Please include both the actuals and targets for each year of the 2013-2020 period. Please specify the basis of the information provided in response (i.e. annual actuals and annual targets or rolling average actuals and rolling average targets, or some other basis).

2020 Nuclear Benchmarking Report

F2-Staff-197
Exhibit F2 / Tab 1 / Schedule 1 / Attachment 2 / p. 6

Question(s):

a) Please file Table 1 at Exhibit F2 / Tab 1 / Schedule 1 / Attachment 2 / p. 6 for each year 2008-2019 (as available). If targets were set on a rolling average basis for those years (which are comparable to the actuals that are presented), please also provide the relevant targets.

F2-Staff-198
Exhibit F2 / Tab 1 / Schedule 1 / Attachment 2 / pp. 65, 97

Preamble:

The Electric Utility Cost Group (EUCG) database is the source for the cost benchmarking data used for the value for money metrics.

Question(s):

a) Please advise whether the peers in the EUCG database include both the EUCG Panel in Table 8 and the remaining EUCG members in the table below Table 8 at Exhibit F2 / Tab 1 / Schedule 1 / Attachment 2 / p. 97.

b) Please confirm that the TGC / MWh metric is the most comprehensive value for money metric that is benchmarked by OPG.

c) Please provide the rank (i.e. # / total comparators) for each of Pickering NGS and Darlington NGS for the TGC / MWh metric on both a normalized and non-normalized basis.

F2-Staff-199
Exhibit F2 / Tab 1 / Schedule 1 / Attachment 2 / p. 70

Question(s):

a) The terms ‘site capacity’ and ‘unit capacity’ appear to be used interchangeably. Please provide the definition for both ‘site capacity’ and ‘unit capacity’. In the response, please clarify if the two different terms are being used to discuss the same concept or two separate concepts.

b) Please provide a detailed explanation for third quartile performance for Darlington NGS and fourth quartile performance for Pickering NGS even with the normalizations applied.

F2-Staff-200

Exhibit F2 / Tab 1 / Schedule 1 / Attachment 2 / pp. 84, 88-89

Preamble:

OPG provided a comparison of its performance on three key metrics (WANO Nuclear Performance Index, Unit Capability Factor, TGC / MWh) relative to certain peers at the major operator level.

Question(s):

a) Please reference which peer group(s) are used for each of the above noted metrics. Please provide specific references to the "panel" tables provided starting at p. 96 of Exhibit F2 / Tab 1 / Schedule 1 / Attachment 2.

b) Please provide a detailed discussion of OPG's performance (11 out of 13 on a normalized basis and 13 out of 13 on a non-normalized basis) at the major operator level.

c) Please provide a discussion of the decline in performance relative to the peer group from 12 out of 13 to 13 out of 13 between 2017 and 2019.

ScottMadden Nuclear Benchmarking Reports

F2-Staff-201

Exhibit F2 / Tab 1 / Schedule 1 / Attachment 3 / p. 1

Preamble:

ScottMadden recommended that OPG focus on site-level comparisons of performance for Pickering NGS and Darlington NGS rather than operator-level comparisons in the future. This represents an evolution in ScottMadden's guidance from 2009.

Question(s):

a) Please provide the excerpt of ScottMadden's guidance from 2009 with respect to the issue of operator-level and site-level comparisons (including a reference to the application in which this guidance was filed).

F2-Staff-202

Exhibit F2 / Tab 1 / Schedule 1 / Attachment 3 / pp. 9, 13

Preamble:

OPG provided the following normalization summary for the TGC / MWh metric.

Normalization Summary - TGC/MWh		
3-Year (2016-2018)	**Darlington**	**Pickering**
TGC/MWh - Non-Normalized	59.06	67.76
Total Generating Costs [TGC] (C $K)		
Non-Normalized TGC	3,847,416	4,215,170
Refurbishment Adjustment	(512,734)	-
Reactor Type Adjustment	(852,100)	(852,100)
Unit Age Adjustment	93,935	(55,131)
Normalized TGC	2,576,517	3,307,938
Generation (GWh)		
Non-Normalized Generation	65,147	62,210
Outage Adjustment	3,287	4,901
Normalized Generation	68,434	67,111
TGC/MWh - Fully Normalized	37.65	49.29

Question(s):

a) Please confirm that the above normalization summary is based on 2018 information (three-year rolling average - 2016-2018).

b) Please provide a normalization summary for each year 2017, 2018 and 2019 (using annual information as opposed to a rolling average).

c) Please provide a normalization summary for 2017 and 2019 on a rolling average basis (similar to the 2018 normalization summary reproduced above).

d) Please provide a normalization summary for 2017, 2018 and 2019 on a rolling average basis (similar to the 2018 normalization summary reproduced above) showing the impact of the normalizations on the indicator for first, second and third quartile performance.

e) Please provide the refurbishment adjustment breakdown as shown in Table 3 of Exhibit F2 / Tab 1 / Schedule 1 / Attachment 3 for 2017 and 2019.

f) Please identify whether ScottMadden has completed a normalization analysis for any of the other nuclear operators that have contracted its services in the past. In the response, please identify whether normalization is standard practice when benchmarking nuclear operators.

F2-Staff-203

Exhibit F2 / Tab 1 / Schedule 1 / Attachment 4 / pp. 6-11

Question(s):

a) Please confirm whether ScottMadden was given raw accounting data or data pre-filtered by OPG for their validation of the OPG Darlington NGS refurbishment adjustment and normalization.

b) Please discuss the controls in place to ensure that cost attribution based on management assignments (i.e. Scenario 1: Management Assignment or Proportionate Support Allocation) are not subjective.

c) Depending on the specific OPG division / group, different adjustment amounts could be calculated depending on the cost attribution scenario used. Please comment on the efficacy of the current adjustment strategy given the above.

F2-Staff-204

Exhibit F2 / Tab 1 / Schedule 1 / Attachment 4 / p. 7
Exhibit A1 / Tab 3 / Schedule 1 / pp. 6-7

Preamble:

OPG provided a table highlighting the cost attribution scenarios used for the various category of costs. OPG noted that the cost attribution scenarios are based on OPG's 2017 organizational structure. OPG underwent a major corporate realignment in 2020.

Question(s):

a) Please discuss whether this organizational change impacts the manner in which the normalization methodology will be applied in 2020. Please describe in detail.

F2-Staff-205
Exhibit F2 / Tab 1 / Schedule 1 / Attachment 5 / pp. 3, 7-10

Question(s):

a) Please identify whether any of OPG's peers in the EUCG normalize their TGC using the same factors that are used by OPG for any benchmarking they may do. Please identify whether any of OPG's peers in the EUCG normalize their TGCs by other factors not used by OPG for any benchmarking they may do.

b) Please provide the analysis of variance (ANOVA) results from the multiple linear regression used to quantify the relationship between variables for the predictive TGC model. Specifically, please comment on the statistical significance of the results.

c) The multiple linear regression used to develop the mathematical model for TGC included variables for reactor type, site capacity, and unit age. However, site capacity was not used when calculating Pickering NGS and Darlington NGS's normalized TGC. Please comment as to why this variable was not included in the regression for normalized TGC and how the results would have differed had it been included. In the response, please elaborate further on why an adjustment to station MWhs produced would be required if site capacity were considered in the results.

d) Please provide a directional indication of benchmarking results for each of Pickering NGS and Darlington NGS (i.e. does it result in a higher or lower ranking) due to the application of a normalization to TGC / MWh on the basis of site capacity.

e) Please provide how much above / below the median each of Darlington NGS and Pickering NGS are relative to the median age (used to determine the age-related adjustment).

f) ScottMadden stated that "we were unable to develop a sufficiently predictive model for cost performance (TGC / MWh)" (Exhibit F2 / Tab 1 / Schedule 1 / Attachment 5 / p. 7). However, a comparative figure of adjusted TGC / MWh for the EUCG panel, including Pickering NGS and Darlington NGS, is provided on page 10 at Exhibit F2 / Tab 1 / Schedule 1 / Attachment 5. Considering this, please explain how the noted figure was produced.

F2-Staff-206

Exhibit F2 / Tab 1 / Schedule 1 / Attachment 5 / pp. 8, 10

Question(s):

a) Please comment on the overall benchmarking performance of both Pickering NGS and Darlington NGS when compared to the other Canadian CANDU utilities (i.e., Bruce Power, NB Power) in those areas where comparable data is available.

b) Please further elaborate on the rationale for focusing only on North American nuclear stations for the benchmarking studies completed.

F2-Staff-207

Exhibit F2 / Tab 1 / Schedule 1 / Attachment 5 / pp. 11-13

Question(s):

a) ScottMadden stated that only nine nuclear operators responded to the survey for the Custom Nuclear Outage Benchmarking Study. The report then states that 19 CANDU plants, 19 Pressurized Water Reactor (PWR) plants, and 9 Boiling Water Reactor plants participated in the study. Please confirm that all 47 nuclear plants are operated by one of the nine that participated in the study.

b) Considering this sample size in relation to the number of members in the EUCG Nuclear Committee, please comment on the appropriateness of using a sample size of nine nuclear operators for the Custom Nuclear Outage Benchmarking Study.

Fleet Wide Initiatives

F2-Staff-208
Exhibit F2 / Tab 1 / Schedule 1 / Attachment 1 / p. 1

Preamble:

OPG provided an update on six fleet wide initiatives identified in its 2017-2021 Payment Amounts Proceeding. These initiatives include: (a) Parts Improvement; (b) Outage Improvement; (c) Equipment Reliability; (d) Human Performance; (e) Nuclear Inventory; and (f) Workforce Planning and Resourcing.

Question(s):

a) Please provide an estimate of the cost savings or increased production resulting from each initiative.

b) Please detail how these cost savings or increased production have been reflected in the revenue requirement or nuclear production forecast for the 2022-2026 Custom IR term.

Pickering Optimized Shutdown

F2-Staff-209
Exhibit F2 / Tab 1 / Schedule 1 / p. 25
Exhibit F4 / Tab 1 / Schedule 1 / p. 9

Preamble:

OPG noted that the application reflects its plan to safely optimize the shutdown of Pickering NGS by operating all six units until September 2024, five of the six units through 2024, and the remaining four units until December 2025, as per the 2020-2026 Business Plan.

In other areas of the application, OPG describes the accounting EOL date as December 31, 2022 for Pickering NGS Units 1 and 4 and December 31, 2024 for Pickering NGS Units 5-8 (for example, see Exhibit F4 / Tab 1 / Schedule 1 / p. 9).

Question(s):

a) Please provide a table that sets out for each area of the application (e.g. rate base (including working capital), OM&A, compensation (including pensions + OPEBs), depreciation, production forecast, etc.), whether the accounting EOL date applies or the Pickering Optimized Shutdown date applies.

b) Please advise whether, throughout the application, OPG has used the language: (i) “accounting EOL” to describe Units 1 and 4 closure at December 31, 2022 and Units 5-8 closure at December 31, 2024; and (ii) “Pickering Shutdown” to describe the updated closure dates of September 2024 and December 2024 for Units 1 and 4 and December 2025 for Units 5-8.

F2-Staff-210

Exhibit F2 / Tab 1 / Schedule 1 / p. 25
Exhibit B1 / Tab 1 / Schedule 1

Question(s):

a) Please provide an itemized listing and pertinent details of all in-service additions allocated to Pickering NGS over the Custom IR term. In the response, please identify the amount of in-service additions allocated to Pickering NGS that OPG is seeking approval for in the current application. Please use the tabular format outlined below when providing the response.

In-Service Addition Name	In-Service Addition Details	2022 ($M)	2023 ($M)	2024 ($M)	2025 ($M)	2026 ($M)	IR Term In-Service Additions
		(a)	(b)	(c)	(d)	(e)	**Sum of (a) thru (e)**

F2-Staff-211

Exhibit F2 / Tab 1 / Schedule 1 / p. 25
Exhibit B1 / Tab 1 / Schedule 1

Question(s):

a) Using the tabular format below, please provide Cash Working Capital, Fuel Inventory, and Materials & Supplies balances for Pickering on an annual basis from 2016 to 2026. Please provide actual balances for historical years and forecast balances for future years.

($M)	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast
Cash Working Capital											
Fuel Inventory											
Materials & Supplies											

F2-Staff-212

Exhibit F2 / Tab 1 / Schedule 1 / pp. 25, 27
Exhibit H1 / Tab 1 / Schedule 1 / p. 38

Preamble:

OPG proposed $50 million of enabling costs to support the Pickering Optimized Shutdown. These enabling costs are reflected in nuclear base, outage and project OM&A.

OPG also proposed the establishment of the Pickering Closure Costs Deferral Account in accordance with Section 5.6 2 of O. Reg. 53/05. This account will record any employment-related costs, and non-capital costs related to third party service providers incurred by OPG that arise from any Pickering closure activities.

OPG noted that O. Reg 53/05 specifies that Pickering NGS closure costs can be incurred before or after the closure of a Pickering NGS unit, but does not include costs that are eligible for reimbursement to OPG under the ONFA.

Question(s):

a) Please confirm that the requested $50 million in enabling costs in support of Pickering Optimized Shutdown are intended solely for ensuring continued operations of Pickering NGS until 2025 and that no costs associated with closure and decommissioning are included in these enabling costs. If there are costs associated with closure and decommissioning that are included in the enabling costs, please identify and provide the respective cost.

b) Please confirm that OPG intends to record all Pickering NGS closure-related costs in the proposed Pickering Closure Costs Deferral Account (and no

Pickering NGS closure-related costs are reflected elsewhere in the proposed revenue requirement).

c) Please provide a detailed listing of the types of closure-related costs that OPG expects to incur (e.g. severance, training, etc.). Please also provide a high-level estimate of the closure-related costs (by cost type) that OPG expects to incur. Please discuss how OPG intends to minimize these closure costs.

d) Please provide a draft accounting order for the Pickering Closure Cost Deferral Account.

e) Please provide the period over which OPG expects that it will seek to dispose of any balance in the Pickering Closure Cost Deferral Account.

f) Please advise whether an estimate of the Pickering NGS closure-related costs has been considered as part of OPG's rate smoothing proposal. If not, please explain why.

g) Please identify where the Pickering NGS decommissioning costs are reflected in OPG's revenue requirement and confirm that none of these costs are reflected in the enabling costs or will be recorded in in the Pickering Closure Costs Deferral Account.

h) Please confirm that OPG intends to record any variances between the proposed $50 million of Pickering NGS enabling costs and the actual costs in the CRVA.

i) Using the template provided below, please provide an itemized listing and brief description of all material initiatives (capital and non-capital) included as part of the requested $50 million of Pickering Optimized Shutdown enabling costs.

Initiative Name	Initiative Description	Total Cost ($)

F2-Staff-213

Exhibit F2 / Tab 1 / Schedule 1 / pp. 25-28

Preamble:

OPG noted that for the Pickering NGS Units 5-8 to operate beyond 2024, OPG is required to complete a reassessment of the continued validity of the Periodic Safety

Review (PSR), revise the Integrated Implementation Plan (IIP) actions as required, and notify the CNSC of the results of both by December 31, 2022, in support of an application for a licence amendment. In addition to the PSR reassessment, OPG noted that it will execute its Fuel Channel Life Cycle Management Plan and complete Component Condition Assessments to ensure that Pickering NGS components can be safely operated to 2025. OPG stated that it will continue, leading up to the CNSC submission, to validate technical analysis to support CNSC approval to operate Pickering NGS units to 2025.

Question(s):

a) What type of description / criteria does OPG use to define what constitutes an IIP-type action? Please provide relevant materials, such as charters, business cases or internal documentation, that define / establish such criteria.

b) Please identify whether efforts toward the PSR reassessment and IIP action revision have begun. If so, please comment on the status of these efforts. In the response, please identify all anticipated IIP actions that will be undertaken during the 2022 to 2026 period.

c) Using the tabular format outlined below, please provide the details and costs associated with all IIP actions started or completed since January 1, 2018.

IIP Action Name	IIP Action Description	Year Started	Year Completed	Cost ($M)

d) Please identify whether any of the completed or planned IIP activities directly or in-directly support the actual shutdown of Pickering NGS. If so, please identify the activities and their associated costs.

e) Please identify whether the CNSC had any concerns with the PSR submitted as part of Pickering NGS's re-licensing in 2018. In the response, please identify specific CNSC concerns that were raised, if any, and detail if OPG is addressing such concerns in this iteration of the PSR. If applicable, please clearly identify the actions being undertaken and their associated costs.

f) Please provide an update on the status of the CNSC approval that is required to operate Pickering NGS Units 5-8 past 2024. If there are any developments that may impact the Pickering Optimized Shutdown, please advise.

g) Please confirm that if OPG were to not receive the license amendment from the CNSC the result would be that Units 5-8 would be shutdown by the end of 2024 (along with Units 1 and 4).

h) Please outline OPG's preferred contingent approach to either changing payment amounts or recording balances should any Pickering NGS unit not be allowed to operate until the targeted shutdown date at the end of 2025.

i) Please identify whether OPG has evaluated de-rating any of the Pickering NGS units to ensure its continued operation to 2025. In the response, please identify whether OPG has conclusively decided to de-rate or plans to evaluate de-rating any of the Pickering NGS units between 2021 and 2025.

j) Please identify all planned component replacements or refurbishments with a material total cost (capital, and non-capital) that will be undertaken because of a Component Condition Assessment.

k) Please advise whether OPG has any ongoing preliminary contingencies involving the operation of any Pickering NGS units past the current 2025 target of the Pickering Optimized Shutdown. If so, please discuss those contingencies, provide the associated costs of such contingencies, and describe whether any costs are recorded in the proposed 2022-2026 revenue requirement or any of OPG's DVAs.

l) Based on the current outage frequency, please identify the year that each Pickering NGS unit will achieve 295,000 EFPH. As applicable, please provide commentary for any Pickering NGS unit that achieves this threshold prior to, or subsequent to, 2025.

Nuclear Staffing Benchmarking Study

F2-Staff-214

Exhibit F2 / Tab 1 / Schedule 1 / Attachment 6
Exhibit F2 / Tab 1 / Schedule 1 / Table 2
Exhibit A1 / Tab 3 / Schedule 1 / pp. 6-7

Question(s):

a) Please confirm that Goodnight Consulting's (Goodnight) staffing benchmarking study (the Goodnight Study) was drafted before OPG made the organizational change described at Exhibit A1 / Tab 3 / Schedule 1 / pp. 6-7.

b) Please confirm that the Pickering Optimized Shutdown was not considered by Goodnight in its study.

F2-Staff-215

Exhibit F2 / Tab 1 / Schedule 1 / Attachment 6 / pp. 3, 16
Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1 / p. 1
Exhibit F4 / Tab 3 / Schedule 1 / Attachment 2 / p. 3
Exhibit F3 / Tab 1 / Schedule 1 / Table 7

Preamble:

Goodnight noted that it benchmarked 5,016 OPG nuclear staff and long-term contractors and 2,404 OPG nuclear personnel were excluded from the benchmarking.

Question(s):

a) Please advise whether any of the categories for exclusions from the benchmarking (e.g. fuel handling, major projects, etc.) have changed since the last study. If so, please discuss those changes.

b) Please explain the difference between the 7,420 total OPG nuclear personnel referenced (5,016 benchmarked and 2,404 excluded) in the Goodnight Study to the 8,643.9 nuclear FTEs for 2019 referenced as part of the compensation evidence at Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1 / p. 1.

c) Please explain the difference between the 7,420 total OPG nuclear personnel referenced (5,016 benchmarked and 2,404 excluded) in the Goodnight Study and the total 2019 FTE count of 7,366.7 shown at Exhibit F2 / Tab 1 / Schedule 1 / Table 2.

d) Please explain the difference between the total 2019 FTE count of 7,366.7 shown at Exhibit F2 / Tab 1 / Schedule 1 / Table 2 and the total 2019 FTE count of 8,643.9 at Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1.

e) Please explain the difference between the 7,420 total OPG nuclear personnel referenced (5,016 benchmarked and 2,404 excluded) in the Goodnight Study to the 9,182 total OPG personnel referenced (7,752 benchmarked and 1,430 not benchmarked) in the Willis Towers Watson (WTW) Total Compensation Benchmarking Study at Exhibit F4 / Tab 3 / Schedule 1 / Attachment 2 / p. 3.

f) Please explain the difference between the 5,016 benchmarked in the Goodnight Study to the 7,752 OPG personnel benchmarked in the WTW Total Compensation Benchmarking Study at Exhibit F4 / Tab 3 / Schedule 1 / Attachment 2 / p. 3.

F2-Staff-216
Exhibit F2 / Tab 1 / Schedule 1 / Attachment 6 / p. 13

Question(s):

a) Please explain how the 1,890 hours / year = 1 FTE figure was derived. Please provide rationale supporting the appropriateness of this figure.

F2-Staff-217
Exhibit F2 / Tab 1 / Schedule 1 / Attachment 6 / p. 15

Question(s):

a) Please explain why the staffing data from other non-OPG CANDU reactors was not sufficient to develop realistic benchmarks for OPG.

F2-Staff-218
Exhibit F2 / Tab 1 / Schedule 1 / Attachment 6 / p. 21

Question(s):

a) Please discuss whether OPG has reviewed the 13 functional areas that have the largest functional variances from the benchmarks as part of its reorganization effort that took place in 2020. If so, please discuss the outcome of that review.

F2-Staff-219
Exhibit F2 / Tab 1 / Schedule 1 / Attachment 6 / p. 28

Preamble:

Goodnight excluded 629 individuals due to their dedication on the DRP. At the completion of these individuals' DRP assignments, OPG will need to determine their roles in the organization relative to overall staffing and organization goals.

Question(s):

a) Please confirm that the referenced 629 individuals were fully dedicated to the DRP and did no other work.

b) Please provide a breakdown of the 629 employees by employment type. Specifically, please discuss how many of these employees are regular full-time employees that would have worked at OPG in 2019 regardless of the DRP. Specifically, please discuss how many of these 629 employees were already employed by OPG prior to the DRP. Please explain why the regular full-time employees should not be included in the benchmarking.

F2-Staff-220
Exhibit F2 / Tab 1 / Schedule 1 / Attachment 6 / p. 31

Question(s):

a) Please explain how Goodnight confirmed that the information provided by the companies to which OPG is benchmarked remove all short-term and outage contractors and personnel working on major initiatives. Specifically, please discuss whether Goodnight audits the information provided by the utilities in the peer group to ensure comparability.

b) Please advise whether different companies have different definitions for major initiatives.

F2-Staff-221
Exhibit F2 / Tab 1 / Schedule 1 / Attachment 6 / pp. 36-38

Preamble:

Goodnight noted that technical adjustments were utilized to derive the 2-Unit CANDU staffing benchmark from the PWR.

Goodnight further applied a scaling factor of 1.8 (for most functions) to adjust from a 2-unit plant to a 4-unit plant.

Question(s):

a) Please provide the raw adjustments made in Goodnight's previous staffing study for OPG.

b) Please provide detailed rationale supporting the appropriateness of the technical adjustments made to the following staffing functions at Exhibit F2 / Tab 1 / Schedule 1 / Attachment 6 / p. 36:

   i. Admin
   ii. Budget / Accounting
   iii. Engineering – Reactor
   iv. Human Resources

c) Please provide the scaling factor used in Goodnight's previous staffing study for OPG to adjust from a 2-unit plant to a 4-unit plant.

d) Please provide the methodology used to derive the 1.8 scaling factor and provide detailed rationale supporting the 1.8 scaling factor at Exhibit F2 / Tab 1 / Schedule 1 / Attachment 6 / p. 38.

e) Please confirm that an escalator of 1.14x was applied to all of the staffing functions marked with a "1" to scale from a 35-hour work week to a 40-hour work week at Exhibit F2 / Tab 1 / Schedule 1 / Attachment 6 / p. 38.

f) Please explain all of the "ratio" adjustments made to the various job functions at Exhibit F2 / Tab 1 / Schedule 1 / Attachment 6 / p. 38.

F2-Staff-222
Exhibit F2 / Tab 1 / Schedule 1 / Attachment 6 / p. 41

Question(s):

a) Please provide the management ratio used in Goodnight's previous staffing study for OPG.

b) Please provide detailed rationale supporting the 3.9% management ratio.

F2-Staff-223
Exhibit F2 / Tab 1 / Schedule 1 / Attachment 6 / p. 42

Preamble:

The full scaling factor to adjust from a two-unit plant to a four-unit plant appears to have been applied to Darlington NGS.

OEB staff understands that Darlington NGS Unit 2 was offline for all of 2019 (and OPG personnel that are working on the DRP are not included in the benchmarking analysis).

Question(s):

a) Please explain why Darlington NGS has been applied the full scaling factor to reflect the adjustment from a two-unit plant to four-unit plant.

b) Please provide the benchmark results if Darlington NGS was scaled to a three-unit plant (instead of a four-unit plant).

Nuclear Operations OM&A

Base OM&A

F2-Staff-224
Exhibit F2 / Tab 2 / Schedule 1 / Table 1
Exhibit E2 / Tab 1 / Schedule 2 / Table 1b
Exhibit D2 / Tab 2 / Schedule 1 / p. 7

Preamble:

OPG's base OM&A costs are relatively flat over the 2022-2024 period (prior to the shutdown of Pickering NGS). OEB staff notes, however, that there are varying DRP-related planned outage days in those years.

Question(s):

a) Please confirm that the base OM&A costs exclude costs associated with the DRP.

b) Please confirm that the base OM&A costs include costs associated with planned outages (excluding outages for the DRP).

c) Please provide the monthly base OM&A costs for 2022-2026 attributable to Darlington NGS. Please discuss how the varying number of units being offline in a given month for refurbishment during the 2022-2026 Custom IR term has been reflected in the proposed base OM&A costs. For example, in 2022 there are 685 DRP-related planned outage days (reflecting that in some months two units are offline for refurbishment). While in 2023, there are 838 DRP-related planned outage days (reflecting that in some months three units are offline for refurbishment).

F2-Staff-225
Exhibit F2 / Tab 2 / Schedule 1 / Table 1
Exhibit F2 / Tab 2 / Schedule 1 / Attachment 1

Question(s):

a) Please provide a further breakdown of the operations and project support costs by key functions (e.g. provide costs for each of the key functions within the Enterprise Projects category: Nuclear Projects, Enterprise Project Management Office, Commercial Management & Project Assurance) explained in Exhibit F2 / Tab 2 / Schedule 1 / Attachment 1 / Section 2.0, for each year 2016-2026.

F2-Staff-226
Exhibit F2 / Tab 2 / Schedule 1 / Table 2

Question(s):

a) Please provide a table that shows actual (or estimated actual) base OM&A, planned base OM&A and OEB-approved base OM&A (if possible to apply OEB-approved adjustments at the resource type level) for 2017-2021 on a resource type basis.

b) Please discuss the drivers for variances between actual and planned / OEB-approved base OM&A at the resource type level. Specifically, please include a discussion (on a resource type basis) of the impact that outages and refurbishment at the nuclear stations had on base OM&A.

c) Please confirm that the total spend between 2017-2021 on purchased services in the base OM&A category is $655.8 million (or an average of $131.2 million / year). Please confirm that over the 2022-2025 period (prior to the total shutdown of Pickering NGS), OPG intends to spend $617.3 million (or $154.3 million / year on average) on purchased services. Please explain the increased annual spending on purchased services in the 2022-2025 period relative to 2017-2021.

d) Please file a breakdown of the proposed 2022-2026 base OM&A amounts (on a resource type basis) by station.

F2-Staff-227
Exhibit F2 / Tab 2 / Schedule 2 / pp. 3-4

Preamble:

OPG noted that a key driver of the decrease in base OM&A costs between 2023 and 2026 is the phased shutdown of Pickering NGS over the 2024-2025 period.

Question(s):

a) Please provide the monthly base OM&A costs for 2022-2026 attributable to Pickering NGS. Please explain how partial year impacts of the Pickering NGS shutdown have been reflected in the proposed base OM&A costs (as applicable).

F2-Staff-228
Exhibit F2 / Tab 2 / Schedule 2 / pp. 4-12

Question(s):

a) Please confirm that for all of the variance discussion for the 2017-2021 period regarding actual / budget relative to OEB-approved for base OM&A (and all other categories of OM&A) are actually comparing actual / budget to planned (as opposed to OEB-approved). Please explain why OPG compares actual / budget to planned (as opposed to OEB-approved) in its variance discussion.

F2-Staff-229
Exhibit F2 / Tab 2 / Schedule 2 / p. 5

Preamble:

OPG noted that total Pickering Extended Operations actual and budgeted OM&A / capital expenditures over the 2016-2021 are forecast to be aligned with the estimate in OPG's 2017-2021 Payment Amounts Proceeding.

Question(s):

a) Please provide the annual budgeted Pickering Extended Operations-related capital and OM&A costs as presented in OPG's 2017-2021 Payment Amounts Proceeding. Please provide a reference to the evidence in OPG's 2017-2021 Payment Amounts Proceeding where these amounts can be found.

b) Please compare the annual budgeted OM&A and capital costs to the actual OM&A and capital costs in each year during the 2016-2021 period. Please also provide the revenue requirement impact of these variances and confirm that those variances are recorded in the CRVA.

F2-Staff-230
Exhibit F2 / Tab 2 / Schedule 2 / Tables 1a-1b

Question(s):

a) Provide the total actual, planned and OEB-approved base OM&A amounts by business unit for the entire 2017-2021 Custom IR term. Please discuss the largest driver(s) for the variance in aggregate for the entire 2017-2021 Custom IR term.

b) If available, by business unit, please provide the reduction that was reflected in OPG's planned base OM&A amounts as presented in OPG's 2017-2021 Payment Amounts Proceeding to reflect Unit 2 not attracting base OM&A costs while it was offline for refurbishment. Please provide the actual impact on base OM&A of Unit 2 being offline for refurbishment. Please explain any variance.

c) Please explain why the entire OEB-approved $30 million compensation disallowance was applied to base OM&A.

Project OM&A

F2-Staff-231
Exhibit F2 / Tab 3 / Schedule 1 / Table 1

Question(s):

a) Please explain why there is no reduction to the infrastructure costs associated with Pickering NGS in 2024 (in the context of a Pickering NGS unit being taken offline in September of that year).

F2-Staff-232
Exhibit F2 / Tab 3 / Schedule 2 / p. 2

Question(s):

a) Please advise whether the infrastructure budget includes any amounts for potential write-offs. If so, please provide the write-off amount for each year 2022-2026.

F2-Staff-233
Exhibit F2 / Tab 3 / Schedule 2 / Tables 1a-1b

Question(s):

a) Provide the total actual (or estimated actual) and planned project OM&A amounts by business unit for the entire 2017-2021 Custom IR term. Please discuss the largest driver(s) for the variance in aggregate for the entire 2017-2021 Custom IR term.

F2-Staff-234
Exhibit F2 / Tab 3 / Schedule 3 / p. 2
Exhibit F2 / Tab 3 / Schedule 3 / Table 1

Question(s):

a) Please confirm that the costs associated with the Annulus Spacer Life Management were not included in the 2017-2021 revenue requirement, were entirely incurred within the 2017-2021 period and are not subject to CRVA treatment.

b) Please explain why the Darlington Primary Heat Transport Motor Oil Seal Leak Repair project is not considered a DRP-related project. Please advise when OPG first knew about the leaks, whether these leaks must be addressed to complete the DRP and whether the costs associated with this project ($47.4 million) were previously included in the $12.8 billion DRP budget.

F2-Staff-235

Exhibit F2 / Tab 3 / Schedule 3 / Tables 1-4
Exhibit F2 / Tab 3 / Schedule 1 / Table 1

Question(s):

a) Please explain why the IFN Stacking Frame Replacement project shows a final completion date of December 2022 when there is no spending in 2022.

b) Please explain why the Fuel Channel Life Extension project shows a final completion date of December 2021 when there is spending in 2022.

c) Please provide rationale supporting the need for the Pickering 58 Digital Control Computer Hardware Modernization project in the context of the Pickering NGS shutdown.

d) Please advise how much of the total Pickering NGS project costs related to projects with total costs of less than $5 million ($34.2 million) are included in the 2022-2026 project OM&A budget and advise in which line items in Table 1 of Exhibit F2 / Tab 3 / Schedule 1 / those amounts are included.

e) Please confirm that the three unallocated projects for Pickering NGS (Polychlorinated Biphenyl Lighting Ballasts Replacement, North Yard Fire Header Repair, D2O Upgrading Plant A Towers Removal) cost $11.5 million in total over the 2022-2026 period (as shown in the Unallocated Projects table under Table 1 of Exhibit F2 / Tab 3 / Schedule 1).

f) Please discuss each of Polychlorinated Biphenyl Lighting Ballasts Replacement, North Yard Fire Header Repair, D2O Upgrading Plant A Towers Removal and explain why these projects are necessary in the context of the Pickering NGS shutdown.

Outage OM&A

F2-Staff-236

Exhibit F2 / Tab 4 / Schedule 1 / p. 3

Preamble:

OPG noted the completion of specific outages requires both base resources and incremental resources. OM&A base resources in the stations or in operations and project support that work on outages are captured in base OM&A. The cost of incremental resources in support of outage execution, and the cost of Inspection and Reactor Innovation Regular, Term and Extended Temporary Employees (ETEs) staff labour, is captured in outage OM&A.

Question(s):

a) Please provide the total actual cost of planned outage work for each year of the 2017-2021 Custom IR term broken down between costs recovered through base OM&A and outage OM&A.

b) Please provide the total cost of planned outage work for each year of the 2022-2026 Custom IR term broken down between costs recovered through base OM&A and outage OM&A.

F2-Staff-237

Exhibit F2 / Tab 4 / Schedule 1 / p. 3

Preamble:

OPG noted that the Darlington NGS units are on a three-year outage cycle but are currently impacted by the refurbishment schedule. As a result, outage OM&A expenditures reflect two regular planned outages in 2021, one regular planned outage in each of 2023 and 2025, and no regular planned outages in 2020, 2022, 2024 and 2026. In addition, as noted above, the units laid up during refurbishment (e.g. Unit 3 during 2020-2023) will be subject to Cyclical Outages. The work activities and associated outage OM&A expenditures for Cyclical Outages are in addition to and separate from the refurbishment of the units.

OPG also noted that Darlington NGS's Unit 2, Unit 3 and Unit 1 are scheduled for a combined six short, post-refurbishment planned outages in 2021-2026 following return to service. These post refurbishment outages will address equipment issues that are expected to arise after the refurbishment is complete and the unit has resumed operations.

Question(s):

a) Please further explain cyclical outages and the requirement for these outages while the units are laid up during refurbishment.

b) Please provide the number of mini outages for each of Units 2, 3 and 1 planned for the 2022-2026 Custom IR term. Please also provide the cost of each mini outage by unit. Please confirm that the budget for the mini outages is split between base OM&A and outage OM&A (and provide a breakdown).

c) Please advise whether a mini outage has already been completed for Unit 2. If so, please provide the actual costs and compare those actual costs to the planned costs for the remaining mini outages. Please also describe any lessons learned from mini outages completed to date and how those lessons will be applied to the future mini outages.

F2-Staff-238

Exhibit F2 / Tab 4 / Schedule 1 / Tables 1, 2a-3c

Question(s):

a) Please provide the total actual and planned outage OM&A amounts by division for the entire 2017-2021 Custom IR term. Please discuss the largest driver(s) for the variance in aggregate for the entire 2017-2021 Custom IR term.

b) Please provide the variance between actual and planned outage OM&A by resource type for each year during the 2017-2021 Custom IR term. Please discuss any material variances on a resource type basis.

c) Please provide the total actual and planned outage OM&A amounts on a resource type basis for the entire 2017-2021 Custom IR term. Please discuss the largest driver(s) for the variance in aggregate for the entire 2017-2021 Custom IR term.

Nuclear Fuel Costs

F2-Staff-239

Exhibit F2 / Tab 5 / Schedule 1 / p. 2
Exhibit D2 / Tab 1 / Schedule 3 / Tables 4a and 4b

Preamble:

OPG stated that there are four one-time, full loads of new fuel into the refurbished reactors at Darlington NGS over the 2020-2026 period.

Line 7 of Tables 4a and 4b at Exhibit D2 / Tab 1 / Schedule 3 show nuclear operations in-service additions between 2016 and 2026.

Question(s):

a) Please confirm that the capitalized portion of the four one-time, full loads of new fuel mentioned at Exhibit F2 / Tab 5 / Schedule 1 / p. 2 are the same as those shown at Line 7 of Tables 4a and 4b at Exhibit D2 / Tab 1 / Schedule 3. Otherwise, please clarify.

F2-Staff-240

Exhibit F2 / Tab 5 / Schedule 1 / Table 1 / Line 1

Preamble:

Footnote 1 at the above reference states the nuclear fuel costs related to Darlington NGS includes the impact of an initial fuel load required prior to unit start up of each of the refurbished Darlington NGS units.

Question(s):

a) Please clarify the meaning of Footnote 1. Do the values at the above reference include or exclude the capitalized amount?

b) For each year between 2022 and 2026, please clarify what is the new fuel load cost that OPG proposes to capitalize and what is the new fuel load cost that OPG proposes to expense?

F2-Staff-241
Exhibit F2 / Tab 5 / Schedule 1 / p. 6

Preamble:

OPG stated that it seeks to maintain a 12-month supply of fuel bundles.

Question(s):

a) How does the absolute quantity of the 12-month supply (e.g. number of fuel bundles) correspond to the specific production forecast for the given 12-month period? Is it independent from the forecast?

F2-Staff-242
Exhibit F2 / Tab 5 / Schedule 1 / pp. 6-7

Preamble:

OPG stated that it has adopted a minimum uranium concentrate inventory target of 288,000 KgU, representing a four-month supply to feed the production of uranium dioxide. For 2026, OPG has lowered its strategic uranium concentrate inventory target to 225,000 KgU.

Question(s):

a) What is the connection between the reduced inventory target for 2026 and the nuclear production forecast for 2026? For example, does the target continue to represent a four-month supply to feed the production of uranium dioxide, but for fewer operating units?

F2-Staff-243
Exhibit F2 / Tab 5 / Schedule 1 / p. 8
Exhibit F2 / Tab 5 / Schedule 1 / p. 3

Preamble:

OPG stated that following the 2016 review, the range of the limit for “fixed” price arrangements was changed from a minimum / maximum of 50% to 70% to a minimum / maximum of 45% to 65% to reflect the downward pressure in uranium prices at the time.

OPG also stated that the internal review of the uranium coverage risk limits was completed in 2020, and no changes were made to the risk limits.

OPG also stated the forecast price of uranium concentrate over the Custom IR term increases from CDN $117.30 (KgU) / U308 to CDN $136.33 (KgU) / U308 (or 32%).

Question(s):

a) Please explain why OPG did not increase its share of fixed price arrangements following the 2020 review given its forecast of a 32% increase in uranium prices in the context that it reduced its share of fixed price arrangements following the 2016 review on the expectation of lower uranium prices. On what basis did OPG decide to make no changes to the fixed price limits following the 2020 review?

F2-Staff-244
Exhibit F2 / Tab 5 / Schedule 1 / p. 10

Preamble:

OPG provided a discussion of uranium conversion services procurement. OPG stated that its agreement for uranium conversion services for the period 2012-2021 is subject to adjustment for cost (or benefit) sharing if actual cost changes go beyond a threshold. OPG also stated that its Custom IR term forecast assumes no adjustment for cost or benefit sharing.

Question(s):

a) Please clarify how the sharing referenced above figures into to OPG's payment amounts (e.g. how, if at all, does the adjustment for cost (or benefit) sharing flow to ratepayers?

b) Please advise whether the cost (or benefit) sharing threshold has been exceeded at any time between 2012 and 2021.

c) If the response to (b) is yes, please summarize the annual value of adjustment for cost (or benefit) sharing between 2012 and 2021.

F2-Staff-245
Exhibit F2 / Tab 5 / Schedule 2 / pp. 2-5

Preamble:

OPG compared OEB-approved and actual / budgeted nuclear fuel costs between 2017 and 2021. Fuel utilization efficiency is noted as a contributor to variances between approved and actual / budgeted nuclear fuel costs (lower efficiency increases nuclear fuel costs).

Question(s):

a) Please clarify what is meant by fuel utilization efficiency in the context of nuclear fuel. Please indicate how fuel utilization efficiency is measured / expressed and please briefly outline its key determinants.

b) What was OPG's fuel utilization efficiency projection for the period 2017 to 2021 and how did OPG's actual efficiency compare?

c) Please explain why OPG had lower than expected fuel utilization efficiency in three out of the five years between 2017 and 2021.

d) How does OPG's projected nuclear fuel utilization efficiency for the period 2022 through 2026 compare to the projected efficiency and achieved efficiency between 2017 and 2021?

e) Please describe the efforts that OPG is making to achieve nuclear fuel utilization performance, including any efforts to improve utilization in the future.

Darlington Refurbishment OM&A

F2-Staff-246
Exhibit F2 / Tab 7 / Schedule 1 / Table 1

Question(s):

a) Please clarify how much, if any, of the OM&A costs at the reference above relate to the D2O Storage Project.

Darlington New Nuclear OM&A

F2-Staff-247
Exhibit F2 / Tab 8 / Schedule 1 / p. 1

Preamble:

OPG noted that its revenue requirement for the 2022-2026 Custom IR term includes costs to preserve the option to build new nuclear generation at the Darlington NGS. This is consistent with prior government direction that OPG should continue with the environmental process and site licensing process given long lead times for nuclear procurement and construction.

OPG noted that it is seeking approval of annual OM&A costs of $2.2 million, $2.2 million, $2.3 million, $2.3 million, and $2.3 million for the years 2022-2026. OPG further stated that the forecast OM&A costs during the Custom IR term are for work to preserve the option to build new nuclear at Darlington NGS, and do not assume development of a Small Modular Reactor (SMR) generating station, pending the investment decision on the project.

Question(s):

a) Please provide a copy of the government direction referenced for the record of this proceeding.

b) For the same category of costs as requested in the current proceeding (i.e. preserving option to build new nuclear at Darlington NGS excluding any SMR-related costs), please provide the actual / estimated and OEB-approved amounts for the 2017-2021 Custom IR term. Please discuss any variances.

F2-Staff-248
Exhibit F2 / Tab 8 / Schedule 1 / pp. 1, 3-5

Preamble:

OPG forecasted OM&A expenses of $66 million in 2020 and $206 million in 2021 for preliminary planning and preparation expenditures for an SMR generating station at Darlington NGS. There was no forecast of planning and preparation expenditures for the development of an SMR included in OPG’s 2017-2021 Payment Amounts

Proceeding. OPG stated that it will record the preliminary planning and preparation amounts in 2020 and 2021 related to the SMR project in the NDVA.

Question(s):

a) Please file the Memorandum of Understanding signed by the Government of Ontario with respect to the development of SMRs in Canada.

b) Please confirm that the total estimated costs of the preliminary planning and preparation expenditures of $272 million are broken down as follows: (i) Technology Developer Selection - $190 million; (ii) Licensing - $20 million; and (iii) Project Development and Oversight - $62 million.

c) Please confirm that if OPG's investment decision is to not go forward with the construction of an SMR generating station that it will write-off the amounts recorded in the NDVA related to the preliminary planning and preparation work (and not seek recovery of these amounts from ratepayers).

Exhibit F3 – Corporate Support Services

Allocation of Corporate Support Services

F3-Staff-249
Exhibit F3 / Tab 1 / Schedule 1 / p. 2
Exhibit A2 / Tab 2 / Schedule 1 / p. 18

Preamble:

OPG noted that, between 2022-2026, it is planning to reduce its cost structure for post-Pickering NGS operations.

OPG referred to the impact of "diseconomies" of scale due to the reduced asset base and the fixed nature of some costs. OPG stated that it will mitigate those diseconomies by targeting sustainable structural and efficiency improvements across shared functions and processes in the corporate and nuclear support organizations. Specifically, OPG plans to mitigate approximately 90% of corporate and operations support costs tied to Pickering NGS by 2026 which OPG equates to removing an estimated $460 million (in 2026 dollars) of base OM&A from the corporate support services and operations & project support organizations. In estimating this mitigation impact, OPG used its 2016 actual cost structure (escalated to 2026 dollars) as the baseline to recognize initiatives that already began to be implemented over the current IR term.

Question(s):

a) Please explain the remaining 10% of costs that OPG expects to continue to incur in more detail.

b) Please identify the initiatives that have already begun to be implemented over the current IR term that directly contribute to the estimated $460 million reduction.

<u>F3-Staff-250</u>
Exhibit F3 / Tab 1 / Schedule 1 / p. 4

Preamble:

OPG noted that the emergence of the COVID-19 pandemic in 2020 impacted corporate support services costs in a number of ways:

- OPG’s real estate group has engaged additional personnel to carry out enhanced cleaning protocols

- OPG’s supply chain group procured N95 and surgical masks during the early stages of the pandemic

- OPG’s environment, health and safety group assumed responsibility for subsequent purchases of personal protective equipment for the remainder of 2020 and are expected to continue through 2021.

- The Chief Information Office acquired additional software licenses and incremental hardware to enable the workforce to work remotely

Question(s):

a) Please confirm that these COVID-19-related costs are included in 2020 and 2021 actuals.

b) Please provide a breakdown of these costs by year (2020 and 2021) and by corporate support service function.

c) Please advise whether OPG has forecast any of the noted COVID-19-related costs in the proposed 2022-2026 corporate support service costs. If so, please provide a breakdown by corporate support service function.

F3-Staff-251
Exhibit F3 / Tab 1 / Schedule 1 / Tables 1, 3

Question(s):

a) Please advise whether Table 1 at Exhibit F3 / Tab 1 / Schedule 1 includes only corporate support service costs associated with the regulated business (both nuclear and hydroelectric) or both the regulated and unregulated businesses.

F3-Staff-252
Exhibit F3 / Tab 1 / Schedule 2 / p. 3

Preamble:

OPG stated that the reportable variances include "Chief Information Office ($12.3M or 10.0% increase), primarily due to higher software maintenance contract costs reflecting increased investment in XXX."

Question(s):

a) Please explain what OPG intended to refer to in the sentence above.

F3-Staff-253
Exhibit F3 / Tab 1 / Schedule 2 / Table 2a

Question(s):

a) Please provide the total actual (or estimated actual), OEB-approved and planned corporate support service costs by function for the entire 2017-2021 Custom IR term. Please discuss the largest driver(s) for the variance in aggregate for the entire 2017-2021 Custom IR term.

Corporate Support Services Benchmarking Study

F3-Staff-254

Exhibit F3 / Tab 1 / Schedule 1 / p. 6
Exhibit F3 / Tab 1 / Schedule 1 / Attachment 2 / pp. 3, 5, 11-16

Preamble:

In OPG's 2017-2021 Payment Amounts Proceeding, the OEB directed OPG to undertake an independent benchmarking study of Corporate Support functions and costs. OPG retained The Hackett Group (Hackett) to undertake that study.

OPG noted that in the course of providing data to Hackett, it became aware that it included certain costs in the "2016 Study" prepared by Hackett that do not form part of Hackett's taxonomy which had a material negative impact on the benchmarking results as presented in OPG's 2017-2021 Payment Amounts Proceeding (based on 2014 data). OPG requested that Hackett re-state the "2016 Study" results and OPG worked with Hackett to correct the previously submitted 2014 cost data to more accurately align with the Hackett methodology, definitions and taxonomy. Hackett included those restated results in the Hackett benchmarking study submitted as part of this application (which Hackett refers to as the "2019 Study"). OPG also noted that its 2014 overall costs, based on the restatement, were 7% lower than the peer group.

OEB staff has prepared the table set out below that summarizes the restatement discussed in Hackett's "2019 Study."

($M)	Finance Process Cost	Procurement Process Cost	Real Estate & Facilities Mgmt.	ECS Process Cost	HR Process Cost	IT Process + Technology Cost	Total
EB-2016-0152 OPG 2014	$36.6	$25.8	$17.3	$86.4	$31.4	$117.0	$314.5
Restated OPG 2014	$34.4	$19.0	$4.9	$38.2	$31.9	$119.7	$248.1
Costs Removed	**$2.2**	**$6.8**	**$12.4**	**$48.2**	**($0.5)**	**($2.7)**	**$66.4**

Question(s):

a) Please confirm or revise OEB staff's summary table set out above.

b) Please provide the benchmarking results that OPG achieved in the 2016 Study prior to the restatement (i.e. how many % above or below the peer group was

OPG).

c) Please provide a more detailed description of the types of costs that have been removed including the associated dollar amounts. For example, what are the procurement process costs that were removed?

d) Please explain why Hackett revised the peer group scope based on OPG's revised data.

e) Please explain why the types of costs that have now been excluded should not be compared against OPG's peers for benchmarking purposes in the 2019 Study.

f) Please provide a table that compares OPG's 2019 costs based on the scope of costs that was used in OPG's 2017-2021 Payment Amounts Proceeding and the costs that are actually used in the 2019 Study (in a format similar to the table above).

g) Please provide OPG's 2019 benchmarking results based on the scope that was used in OPG's 2017-2021 Payment Amounts Proceeding (i.e. how many % above or below the peer group is OPG).

h) Please advise whether any changes to the normalization of peer data were made between the 2019 Study and the 2016 Study.

<u>F3-Staff-255</u>
Exhibit F3 / Tab 1 / Schedule 1 / Attachment 2 / p. 10

Preamble:

Hackett noted that the technology costs are compared within the IT function.

Question(s):

a) Please confirm that in the 2016 Study, the technology costs were included in each of the functions (as opposed to only the IT function).

b) Please explain why in the 2019 Study, the technology costs are included only in the IT function.

c) Please advise whether including the technology costs in the various functions would impact the overall benchmarking results (i.e. % above or below the peer group). If so, please provide OPG's benchmarking results based on including the technology costs in the various functions.

F3-Staff-256

Exhibit F3 / Tab 1 / Schedule 1 / Attachment 2 / p. 10

Preamble:

The 2019 Study provides a breakdown based on process costs and technology costs. OPG is substantially higher in terms of process costs than the peer group and substantially lower in relation to technology costs as reflected in the table below.

($M)	**Process Cost**	**Technology Cost**	**Total**
OPG	$238.1	$34.5	$272.6
Peer Group	$216.7	$79.5	$296.2
Difference	**$21.4**	**($45.0)**	**($23.6)**

Question(s):

a) Does OPG agree that the higher technology costs and lower process costs among the peer group may indicate that the peer group has shifted more than OPG to automation? If not, what does OPG attribute the substantial difference and inverse relationship related to the process and technology costs to?

b) Given the process costs would be ongoing from year to year, did Hackett undertake any analysis to differentiate between ongoing and one-time technology costs to ensure only ongoing technology costs were included?

Cost Allocation Methodology

F3-Staff-257
Exhibit F3 / Tab 1 / Schedule 4 / p. 1
Exhibit F3 / Tab 1 / Schedule 1 / Table 3
Exhibit F2 / Tab 2 / Schedule 1 / Table 1
Exhibit F4 / Tab 4 / Schedule 1 / Table 3

Preamble:

OPG noted its cost allocation methodology distributes OPG's central and common costs across its operations and to its subsidiary businesses. This includes the costs of corporate support services, operations and project support groups as well as centrally held costs.

a) For each year of the 2022-2026 Custom IR term, please provide the following:

    i. The percentage of OPG's total corporate support service costs (both regulated and unregulated) that is allocated to the nuclear business segment. Please provide this at the same level of detail as Table 3 in Exhibit F3 / Tab 1 / Schedule 1.

    ii. The percentage of OPG's total operations and project support group costs (both regulated and unregulated) that is allocated to the nuclear business segment. Please provide this at the same level of detail as Table 1 in Exhibit F2 / Tab 2 / Schedule 1.

    iii. The percentage of OPG's total centrally held costs (both regulated and unregulated) that is allocated to the nuclear business segment. Please provide this at the same level of detail as Table 3 in Exhibit F4 / Tab 4 / Schedule 1.

b) For each year of the 2017-2021 term, please provide the following:

    i. The percentage of OPG's total corporate support service costs (both regulated and unregulated) that was allocated to the nuclear business segment on an OEB-approved and actual basis. Please also provide the variance between OEB-approved and actual. Please provide this at the same level of detail as Table 3 in Exhibit F3 / Tab 1 / Schedule 1.

ii. The percentage of OPG’s total operations and project support group costs (both regulated and unregulated) that was allocated to the nuclear business segment on an OEB-approved and actual basis. Please also provide the variance between OEB-approved and actual. Please provide this at the same level of detail as Table 1 in Exhibit F2 / Tab 2 / Schedule 1.

iii. The percentage of OPG’s total centrally held costs (both regulated and unregulated) that was allocated to the nuclear business segment on an OEB-approved and actual basis. Please also provide the variance between OEB-approved and actual. Please provide this at the same level of detail as Table 3 in Exhibit F4 / Tab 4 / Schedule 1.

F3-Staff-258
Exhibit F3 / Tab 1 / Schedule 4 / p. 1

Preamble:

OPG noted that the revisions made to the cost allocation methodology that are discussed in the Elenchus Report do not have a material impact on the results of the cost allocations.

Question(s):

a) Please quantify the estimated impact on the results of the costs allocated due to the changes to the methodology.

b) If OPG is not able to quantify the impact, please explain how OPG concluded that there is not a material impact.

Cost Allocation Study

F3-Staff-259
Exhibit F3 / Tab 1 / Schedule 4 / Attachment 1 / p. 17

Preamble:

Elenchus Research Associates Inc. (Elenchus) stated that the unregulated subsidiaries may purchase specific labour services or resources from OPG, on a cost basis. In those circumstances, Elenchus confirmed that a commensurate portion of central and common costs, corresponding to an estimate of such costs for the transferred labour resources is charged or otherwise attributed to the unregulated subsidiaries. For administrative efficiency of the cost allocation process, OPG uses a standard overhead allocation rate to charge these costs, set at approximately 30%.

Question(s):

a) Please describe the basis for the estimate of services / resources that are purchased from OPG by its unregulated businesses.

b) Please provide the amount of services / resources that are forecast to be purchased from OPG by its unregulated businesses during each year of the 2022-2026 Custom IR term and confirm that those amounts operate to offset revenue requirement that otherwise would be allocated to OPG's regulated business.

c) Please provide the actual amount of services / resources that were purchased from OPG by its unregulated businesses during each year of the 2017-2021 period.

F3-Staff-260
Exhibit F3 / Tab 1 / Schedule 4 / Attachment 1 / p. 19

Preamble:

Elenchus stated that external cost drivers are based on data that is independent of the cost allocation process, whereas internal cost drivers are based on values derived as part of the process.

Elenchus noted that OPG removed the use of internal cost drivers and now uses only external cost drivers to simplify and increase efficiency of the cost allocation process.

Question(s):

a) To what extent has accuracy been reduced in relation to allocating costs between the regulated and unregulated businesses due to internal cost drivers no longer being used?

F3-Staff-261
Exhibit F3 / Tab 1 / Schedule 4 / Attachment 1 / p. 19

Preamble:

Elenchus stated that OPG's change to the allocation methodology related to assigning management employee incentive costs on the basis of planned management labour cost dollars (as opposed to using incentive payments in the most recent year) recognizes the inherent uncertainty in translating the historical distribution of incentive payments to future periods.

Question(s):

a) Please explain how the use of management incentive payments across the OPG businesses in the most recent historical year as the basis (which would be based on actuals) would result in less certainty than planned management labour cost dollars (which would be based on estimates).

F3-Staff-262
Exhibit F3 / Tab 1 / Schedule 4 / Attachment 1 / p. 22

Preamble:

OPG informed Elenchus that, beyond the 2020 organizational realignment, there are no significant changes to the functional structure or nature of costs of corporate support and operations support contemplated in the 2020-2026 Business Plan, including through the shutdown of Pickering NGS, which would impact the allocation of costs between OPG businesses. On this basis, Elenchus stated that the existing cost allocation methodology continues to be reasonable for OPG following the Pickering NGS shutdown. In the event functional activities, service delivery models or nature of the costs change materially after the shutdown is executed, the cost allocation methodology should be reviewed.

Question(s):

a) Please explain why a major event like the shutdown of Pickering NGS would not impact the allocation of costs between OPG's businesses.

Regulatory Affairs Costs

F3-Staff-263
Exhibit F3 / Tab 1 / Schedule 3 / Table 1

Question(s):

a) Please confirm that the regulatory affair costs set out in Table 1 of Exhibit F3 / Tab 1 / Schedule 3 reflect only the regulatory affairs costs allocated to the nuclear business. If not, please explain and provide the nuclear allocated amounts.

b) Please confirm that the nuclear allocated regulatory affairs costs are entirely allocated to the base OM&A budget.

c) Please explain the significant intervenor cost awards budgeted in both 2021 ($1.7 million) and 2022 ($2.7 million) and provide the total cost award amount approved in OPG's 2017-2021 Payment Amounts Proceeding.

d) Please explain the significant consultant costs budgeted for the 2024-2026 period (totaling approximately $5 million).

Asset Service Fees

F3-Staff-264
Exhibit F3 / Tab 2 / Schedule 1 / pp. 2-3

Preamble:

Asset service fees are computed in a cost-based manner. The costs included in the computation of the asset service fees are depreciation expense, certain operating costs, property taxes, and a tax-adjusted return earned on these assets.

Question(s):

a) Please confirm that the asset service fee calculation is essentially a revenue requirement calculation.

b) Using Kipling / Wesleyville as the example, please provide:

i. Asset service fee calculations for each year 2022-2026.

ii. Revenue requirement calculations for each year 2022-2026 (assuming the asset was instead included in rate base using the same square footage-based allocation methodology to determine the amount to be apportioned to the nuclear business).

c) Please confirm that the proposed asset service fees for the Kipling / Wesleyville property and its Clarington Corporate Campus property are calculated in the same manner as the asset service fees were previously calculated for OPG's head office building.

F3-Staff-265

Exhibit F3 / Tab 2 / Schedule 1

Preamble:

OEB staff understands that OPG sold its head office building and related parking facility in Toronto in April 2017.

Question(s):

a) Please provide the net gain on the sale of the head office building and related parking facility.

b) Please confirm that OPG did not share any of the proceeds associated with the sale of the head office building and related parking facility with ratepayers.

c) Please confirm that ratepayers have paid asset service fees associated with OPG's head office since OPG was first regulated by the OEB.

d) Please provide the total amount paid by ratepayers through asset service fees related to the head office building since OPG was first regulated by the OEB (both nuclear and hydroelectric). Please provide the total amounts broken down between depreciation, property tax, operating costs and tax-adjusted return.

e) Please confirm that the majority of the cost of the head office building was recovered through asset service fees during the period that OPG was regulated by the OEB (i.e. the regulated businesses were allocated the majority of the cost of the building).

f) In the future, if OPG were to sell its Kipling / Wesleyville property or its Clarington Corporate Campus property (and there was a net gain on the sale of the property), please confirm that OPG would not share any of those net gains with ratepayers.

<u>F3-Staff-266</u>
Exhibit F3 / Tab 2 / Schedule 1 / pp. 3-4

Preamble:

OPG has announced that it will build a new corporate campus in Clarington, Ontario that is expected to be fully completed in 2025. OPG provided the 2024-2026 asset service fees associated with the Clarington Corporate Campus.

Question(s):

a) Please explain why there are asset service fees charged in 2024 when the project is expected to be completed in 2025.

b) Please advise whether OPG has considered any true-up mechanisms for the asset service fees in the circumstance that the project is not completed according to the estimated schedule / budget.

<u>F3-Staff-267</u>
Exhibit F3 / Tab 2 / Schedule 1 / Table 2

Question(s):

a) For each year during the 2017-2021 period, please provide the percentage of the total asset costs that was recovered through asset services fees from the nuclear business on an actual and planned basis.

b) For each year during the 2022-2026 period, please provide the percentage of the total asset cost that is proposed to be recovered through asset service fees from the nuclear business.

c) Please update Table 2 at Exhibit F3 / Tab 2 / Schedule 1 to include a line item for the asset service fee charged to Laurentis Energy Partners (Laurentis) for the use of Darlington reactors to produce Molybdenum-99.

d) Please advise whether any of OPG's subsidiaries other than Laurentis use OPG's regulated nuclear assets to generate revenues (or otherwise support the businesses).

e) Please advise whether OPG could have produced Molydebenum-99 through the regulated business (similar to Cobalt 60 production) and generated other revenues to the benefit of ratepayers. Please discuss why OPG decided to undertake this activity through a subsidiary.

OM&A Purchased Services – Support Services

F3-Staff-268
Exhibit F3 / Tab 3 / Schedule 2 / p. 2

Preamble:

In the original version of Exhibit F3 / Tab 3 / Schedule 2 / p. 2, the New Horizons Systems Solutions contract was described as competitive until October 1, 2009 and then single source after October 1, 2009 (as the original contract was renegotiated). The corrected version of Exhibit F3 / Tab 3 / Schedule 2 / p. 2 now describes the contract as competitive.

Question(s):

a) Please explain the above noted correction. Specifically, please advise whether the contract was actually renegotiated in 2009.

b) If the contract was renegotiated in 2009, please explain what steps OPG has taken to ensure the cost associated with that contract is reasonable and competitive.

Exhibit F4 – Other Operating Costs

Depreciation and Amortization

F4-Staff-269

Exhibit F4 / Tab 1 / Schedule 1 / p. 6
Exhibit F4 / Tab 1 / Schedule 1 / Table 2

Preamble:

With respect to the recommendations from the 2019 depreciation study, OPG stated that it has accepted and, effective January 1, 2021, will implement the recommendations from the study pending formal approval through the 2020 Depreciation Review Committee (DRC) process. OPG's forecast depreciation and amortization expense in this application incorporates the estimated impact of these changes effective January 1, 2021, which is a decrease of approximately $5 million annually.

Question(s):

a) Please confirm that OPG has received formal approval through the 2020 DRC process.

b) Please highlight where the $5 million reduction is reflected in Table 2 at Exhibit F4 / Tab 1 / Schedule 1.

F4-Staff-270

Exhibit F4 / Tab 1 / Schedule 1 / p. 9

Preamble:

OPG stated that based on the actual net book value of the assets as at December 31, 2017, the changes in the Pickering NGS EOL dates and the year-end ARO / ARC adjustment resulted in an estimated reduction in depreciation and amortization expense of approximately $78 million annually.

OPG references Exhibit A2 / Tab 1 / Schedule 1 / Attachment 7 / p. 20 in support of the $78 million reduction. OEB staff cannot locate the referenced document in the application.

Question(s):

a) Please provide the referenced document.

F4-Staff-271
Exhibit F4 / Tab 1 / Schedule 1 / pp. 9-10
Exhibit C2 / Tab 1 / Schedule 1 / pp. 2-3

Preamble:

OPG stated that the Pickering Optimized Shutdown plan includes operating all six units at Pickering NGS through 2024, at which point two units would be shut down (one in September 2024 and one in December 2024), and the remaining four units would operate until the end of 2025.

OPG further stated that the operation of Pickering NGS Units 1 and 4 to December 31, 2024 does not require further CNSC approval and OPG has now achieved high confidence, for depreciation purposes, that the units are expected to operate to December 31, 2024. The high confidence was achieved in 2020 based on inspection and analysis work completed on key components. The 2020 DRC is expected to recommend extending the EOL date for Units 1 and 4 to December 31, 2024, effective December 31, 2020, for financial accounting purposes. OPG noted that it is not able to provide the total revenue requirement impact associated with these changes at this time, primarily because the final year-end information required to calculate the December 31, 2020 ARO / ARC adjustment is not yet available. As noted in pages 2-3 of Exhibit C2 / Tab 1 / Schedule 1, the adjustment will be reflected in OPG's 2020 AFS, to be issued in March 2021. Accordingly, the impacts from the Pickering NGS EOL extension were not reflected in the application.

OPG's 2020 consolidated AFS were issued March 11, 2021.

Question(s):

a) Please provide the 2020 DRC recommendations for the nuclear business.

b) Please provide the December 2020 ARO / ARC adjustment. Please also provide a detailed breakdown of the associated impact to revenue requirement for the prescribed facilities and Bruce.

c) Please explain why OPG is proposing to record the revenue requirement impact associated with the extension of Pickering NGS Units 1 and 4 EOL dates from 2022 to 2024 in the Impacts Resulting from Optimization of Pickering Station End-of-Life Dates (2020) Deferral Account rather than reflecting it in the current revenue requirement. As part of this response, please provide the estimated revenue requirement impact (inclusive of both the depreciation and nuclear liability impacts) associated with the extension of Pickering NGS Units 1 and 4 EOL dates from 2022 to 2024.

Taxes

F4-Staff-272
Exhibit F4 / Tab 2 / Schedule 1 / p. 13
Exhibit F4 / Tab 2 / Schedule 1 / Table 3b

Preamble:

OPG stated that the forecast tax expense for the nuclear facilities in the 2022-2026 Custom IR term is ($16.5) million, ($16.3) million, ($16.4) million, ($16.1) million and ($15.9) million respectively. The negative tax expense for 2022-2026 represents the forecast amount of Scientific Research & Experimental Development (SR&ED) Investment Tax Credits (ITCs) attributed to the nuclear facilities in those years and reflects the impact of the carryover of the forecast nuclear regulatory tax losses of $321.1 million at the end of 2021 and projected nuclear regulatory tax losses of $120.3 million and $82.3 million arising in 2022 and 2023, respectively.

OPG provided the tax losses schedule in Table 3b at Exhibit F4 / Tab 2 / Schedule 1. OEB staff notes that the 2022 opening tax losses brought forward, in the amount of $(321.1) million, is derived from the loss carry-forward ending balance as at the end of 2021, as calculated in OPG's 2017-2021 Payment Amounts Proceeding.

OEB staff also notes that OPG did not provide a supporting schedule 4 (loss carry-forward) from its 2019 tax return.

Question(s):

a) Please provide a copy of schedule 4 (loss carry-forward) from the 2019 tax return.

b) Please provide a loss carry-forward schedule for 2022 to 2026 using the actual loss carry-forward ending balance as at the end of 2019 plus any forecasted losses between 2020 and 2021.

c) Please confirm that the loss carry-forward opening balance in 2022 should be based on the loss carry-forward schedule provided in part (b). If not, please explain.

F4-Staff-273
Exhibit F4 / Tab 2 / Schedule 1 / Table 3
Exhibit F4 / Tab 2 / Schedule 1 / Tables 5-10

Preamble:

OEB staff notes that there are differences in the calculation of Capital Cost Allowance (CCA) for 2016 to 2021 between the amounts disclosed in Table 3 at Exhibit F4 / Tab 2 / Schedule 1 and those shown in Tables 5-10 at Exhibit F4 / Tab 2 / Schedule 1. These differences are shown in the table below:

($M)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
CCA Per Table 3	485	543	627	871	895	1017
CCA Per Tables 5-10	275	336	424	624	675	749
Difference	**210**	**207**	**204**	**246**	**220**	**268**

a) Please explain these differences and provide the reconciliations as necessary.

b) Please clarify the basis of the CCA calculations for 2018 to 2020 in Table 7 to Table 9 at Exhibit F4 / Tab 2 / Schedule 1 (i.e. whether the CCA calculation for the year was based on the legacy half-year rule or the Accelerated Incentive Investment Program (AIIP)) and provide the reason for the basis used.

c) Please explain why the figures in the “50% rule” columns of Table 7 and 8 at Exhibit F4 / Tab 2 / Schedule 1 do not represent 50% of cost of the acquisition in each year.

F4-Staff-274
Exhibit F4 / Tab 2 / Schedule 1 / pp. 12-13
Exhibit F4 / Tab 2 / Schedule 1 / Tables 3-3a
EB-2016-0152 / Payment Amounts Order / Table 19

Preamble:

OPG forecasted the SR&ED ITCs for the 2022-2026 Custom IR term as set out in the table below:

($M)	2022	2023	2024	2025	2026	Average
SR&ED ITC (per Table 3a / Line 28)	-16.5	-16.3	-16.4	-16.1	-15.9	**-16.2**

OEB staff notes that the actual and budgeted SR&ED ITCs in 2017 to 2021 were higher than the ITCs included in OPG's 2017-2021 payment amounts:

($M)	2017	2018	2019	2020	2021
Actual - 2017 to 2019; Budget - 2020 and 2021 (per Table 3 / Line 28)	-29.2	-24.1	-22.9	-20.9	-20
Forecasted and included in OPG's 2017-2021 payment amounts[17]	-18.4	-18.4	-18.4	-18.4	-18.4
Difference	**-10.8**	**-5.7**	**-4.5**	**-2.5**	**-1.6**

Regarding the proposed SR&ED ITCs treatment, OPG stated that it believes that the circumstances observed at the time of OPG's 2017-2021 Payment Amounts Proceeding related to the inherent difficulty in forecasting the nuclear ITCs have not substantially changed, and in fact may be magnified in this application by the need to forecast the ITCs during a period of winding down Pickering NGS operations. On this basis, OPG proposed to continue the treatment of nuclear SR&ED ITCs as implemented in OPG's 2017-2021 Payment Amounts Proceeding, including the current operation of the SR&ED ITC variance account.

Question(s):

a) Please explain why the actual SR&ED ITCs amounts are much higher from 2017 to 2019 than the forecasted amounts for those years in OPG's 2017-2021 Payment Amounts Proceeding.

[17] EB-2016-0152 / Payment Amounts Order / Table 19 / Line 25.

b) Please provide the basis of the forecast SR&ED ITC amounts included in the current application.

c) Please discuss the reasons why the inherent difficulty in forecasting the nuclear ITCs is being magnified due to the winding down Pickering NGS operations.

Compensation and Benefits

F4-Staff-275
Exhibit F4 / Tab 3 / Schedule 1 / pp. 1, 22
Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1

Preamble:

OPG noted that compensation costs for the 2022-2026 Custom IR term are $7,687 million and equivalent to approximately 46% of OPG's forecast 2022-2026 nuclear revenue requirement.

OPG noted that over the Custom IR term, it will undergo a transformational change to prepare for and execute the planned shutdown of Pickering NGS. OPG noted that it is currently planning to reduce its workforce by over 3,000 positions (or approximately 30%).

Question(s):

a) Please advise whether the entire $7,687 million of compensation costs is recovered directly in the revenue requirement through the various OM&A budgets (or a portion of that amount is capitalized).

b) For each year 2017-2026, please chart the total compensation costs to the various cost categories (i.e. base OM&A, project OM&A and any capital budgets to which compensation amounts are capitalized).

c) If any of the compensation costs are capitalized, please provide the capitalized amount (and capitalization percentage) for each year 2017-2026. Please also provide the capitalized amounts on a planned basis for the 2017-2021 Custom IR term. If none of the compensation costs shown in Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1 are capitalized, please explain.

d) For 2017-2021, please provide a comparison of planned and actual FTEs and compensation at the same level of detail as is provided in Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1.

e) Please provide a breakout of executive FTEs and compensation for each year 2017-2026.

f) Please advise whether there are any nuclear-related compensation costs that are not included in the Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1. If so, please quantify those amounts and discuss in which cost categories those amounts are proposed to be recovered.

g) Please provide the calculation supporting the 3,000-position reduction over the Custom IR term (and reconcile to Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1).

h) Please reconcile the 3,000-position reduction (or 30%) to the FTE reductions discussed on page 22 of Exhibit F4 / Tab 3 / Schedule 1 (40% between 2020-2026).

i) Please provide the percentage of FTEs that are allocated to the Pickering NGS in each year 2017-2026.

F4-Staff-276
Exhibit F4 / Tab 3 / Schedule 1 / pp. 5-6, 8
Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1
Exhibit F4 / Tab 3 / Schedule 1 / Attachment 2

Preamble:

OPG noted that it has a mature and experienced workforce. By year-end 2021, approximately 21% of active regular employees will be eligible to retire with an undiscounted pension, with an additional 14% becoming eligible to retire between 2022 and 2026.

OPG noted that it expects that the planned Pickering NGS shutdown will eliminate over 3,000 positions across the organization. OPG noted that one-time costs will include severance obligations for exiting management and unionized employees.

OPG noted that it is hiring Power Workers' Union (PWU) Term employees and Society of United Professionals (Society) ETEs to mitigate the impact of the planned shutdown of Pickering NGS.

Question(s):

a) Please advise how many employees OPG expects to retire during the 2022-2026 Custom IR term. Please provide the percentage of the expected reduction to staffing levels that will be addressed through retirements.

b) Please provide a high-level estimate of the cost savings (in $) of using Term employees and ETEs.

F4-Staff-277
Exhibit F4 / Tab 3 / Schedule 1 / p. 9
Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1

Preamble:

OPG noted that, in 2020, it underwent a corporate realignment, consolidating a number of functions within the company, in preparation for the planned shutdown of Pickering NGS. The realignment has allowed OPG to eliminate over 10% of management positions, the cost savings from which will be carried through the Custom IR term.

Question(s):

a) Please confirm that the 10% reduction to management positions has already occurred.

b) Please advise whether this 10% reduction is reflected in the decrease in management FTEs from 973 in 2020 to 870 in 2021.

c) Please advise whether this 10% reduction is reflected in the decrease in management compensation form $240.4 million in 2020 to $223.4 million in 2021.

d) Please advise whether OPG intends to record any severance costs arising from the 10% reduction to the management positions in the Pickering Closure Deferral Account. If so, please explain why this would be appropriate.

F4-Staff-278
Exhibit F4 / Tab 3 / Schedule 1 / p. 15

Preamble:

OPG noted that the limits on OPG's management compensation have resulted in compensation benchmarking at, or below, the broader labour market for most positions. OPG further stated that the limits on salary increases, while reducing the growth of management compensation costs, have created internal equity issues and impact OPG's ability to attract and retain talent:

- Salary compression exists across OPG with approximately 220 managers currently earning less than the staff they supervise, making it difficult to attract qualified represented staff into management positions. The future salary cap is expected to exacerbate this situation.

- The talent market for skilled management has become highly competitive. OPG's ability to retain and attract into management positions continues to be at risk.

Question(s):

a) Please provide the number of current vacancies that OPG has at the management level.

b) Please explain how the talent market for skilled management is any more competitive today then it was in the past.

F4-Staff-279
Exhibit F4 / Tab 3 / Schedule 1 / pp. 15-16
Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1
Exhibit F4 / Tab 4 / Schedule 1 / Table 3

Preamble:

The Stakeholder Return Program (SRP) is a short-term (i.e. single year) pay for performance incentive plan for eligible management employees, intended to deliver a portion of total compensation on a pay for performance basis. The costs of the SRP are shown separately as a centrally held cost.

The performance incentive costs allocated to the nuclear business appear to be $24.9 million in 2020, $26.9 million in 2021, $27.3 million in 2022, $27.6 million in 2023, $27.8 million in 2024, $24.6 million in 2025, $21.5 million in 2026.

Question(s):

a) Please provide further details with respect to OPG's SRP (including the percentage of compensation that is paid through this program on average).

b) Please provide the 2017-2021 budgeted SRP and the actual SRP paid in those years.

c) Please advise whether the costs associated with the SRP are included in Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1.

d) Please explain why there was no decrease in performance incentive costs between 2020 and 2021 in the context of the 10% reduction to management staff in 2020.

e) Please explain why between 2022 and 2026, OPG is only estimating a reduction $5.8 million (21.2%) in performance incentive costs when approximately 1 in 3 positions across the nuclear business segment is expected to be eliminated.

F4-Staff-280

Exhibit F4 / Tab 3 / Schedule 1 / pp. 18-19
Exhibit F4 / Tab 3 / Attachment 2 / p. 31

Preamble:

OPG provided a chart showing the overview of employee:employer pension contributions (reproduced below).

Employee Pension Contributions*	% of Pensionable Earnings Contributed by Employees (% below / above YMPE / above Earnings Limit)						Contribution Ratio (Employee/Employer)
	MG			PWU		Society	
2014	7	/ 7		5	/ 7	7	24% / 76%
2015	7	/ 7		6	/ 8	7	
2016	7.3	/ 8.25	/ 2	7	/ 9	8	29% / 71%
2017	7.6	/ 9.5	/ 4.5	7.5	/ 10	9	32% / 68%
2018	7.6	/ 9.5	/ 4.5	7.5	/ 10	9	33% / 67%
2019	7.6	/ 9.5	/ 4.5	7.5	/ 10	9	34% / 66%
2020	7.6	/ 9.5	/ 4.5	7.5	/ 10	9	32% / 68%

In the Decision and Order in OPG's 2017-2021 Payment Amounts Proceeding, the OEB directed OPG to file pension and other post-employment benefits (OPEB) evidence that clearly sets out the elements included and excluded in its determination of employee:employer contribution ratios.

OPG stated that the contribution ratio is calculated as the ratio between: (a) the current service cost funding contributions made by OPG to its registered pension plan pursuant to actuarial valuations; and (b) the total amount of contributions made by OPG's employees to the plan.

OPG further stated that funding for special payments toward a plan deficit, if any, is excluded from the calculation. OPG confirmed with Aon that this is the appropriate approach to measure the employee percentage cost-sharing in a single employee pension plan and is consistent with the approach used in the Report on the Sustainability of Electricity Sector Pension Plans (the Leech Report).

OPG noted that Aon has also confirmed that it is appropriate to exclude OPEB costs from the calculation where the plans are pay-as-you-go unfunded arrangements, as is the case for OPG.

Question(s):

a) Please confirm that the manner in which the contribution ratio was calculated in the current proceeding is the same as in OPG's 2017-2021 Payment Amount proceeding.

b) Please advise what types of compensation are included in the determination of the earnings basis used to determine the contribution ratio (e.g. base salary, performance pay, special payments, overtime, etc.).

c) Please provide the average and distribution of the contribution ratios of the organizations included in the pension and benefits comparator group in the WTW Total Compensation Benchmarking Study.

d) If available, please provide the contribution ratio of Bruce Power.

e) Please explain how OPG's calculation of earnings for pension determination compares to the practices of the comparator group.

f) Please provide an updated version of the employee:employer pension contribution chart that includes:

    i. Special payments

    ii. OPEB

    iii. Both special payments and OPEB

g) Please file the Leech Report on the record of this proceeding. Please discuss why OPG believes that the Leech Report excludes special payments and provide specific references within the Leech Report.

h) Please advise whether the Leech Report includes or excludes OPEB costs from the contribution ratio calculation.

i) Please explain why it is appropriate to exclude special payments and OPEBs from the contribution ratio calculation.

j) Please advise whether Aon has reviewed OPG's special payments. If so, please provide Aon's view on whether the special payments made by OPG are considered typical relative to appropriate comparators.

k) Please advise whether Aon has reviewed OPG's OPEBs. If so, please provide Aon's view on whether the OPEBs offered by OPG are considered typical relative to appropriate comparators.

F4-Staff-281
Exhibit F4 / Tab 3 / Schedule 1 / p. 19

Preamble:

OPG noted that PWU and Society employees can retire with an undiscounted pension when their age plus service equals 82 (Rule of 82). For service after March 31, 2025, the eligibility for an undiscounted pension will be changed to the Rule of 85.

Question(s):

a) Please advise whether the Rule of 85 or the Rule of 90 (or some other Rule) is more typical in public service pension plans.

F4-Staff-282
Exhibit F4 / Tab 3 / Schedule 1 / p. 20

Preamble:

OPG noted that over the Custom IR term, the cost associated with the share performance plan (i.e. grant of Hydro One shares for certain eligible employees) is less than the cost savings from the pension reforms that apply to all employees (existing and new).

Question(s):

a) Please provide the cost of the share performance plan and the cost savings resulting from the pension reforms for the 2022-2026 Custom IR term.

F4-Staff-283
Exhibit F4 / Tab 3 / Schedule 1 / p. 21

Preamble:

OPG noted that over the Custom IR term, overtime costs typically account for about 7% of the average compensation costs for OPG's nuclear facilities.

Question(s):

a) Please provide the overtime costs as a percentage of compensations costs for each year during the 2017-2021 Custom IR term on a planned and actual basis.

b) Please provide the overtime costs as a percentage of compensations costs for each year during the 2022-2026 Custom IR term.

Compensation Benchmarking Summary

F4-Staff-284
Exhibit F4 / Tab 3 / Schedule 1 / p. 23

Preamble:

WTW stated that it considers compensation benchmarking results to be at market if they are within +/- 10% of the target market positioning.

OPG's target market positioning for purposes of talent attraction and retention continues to be the 50th percentile for positions in the non-nuclear authorized (or standard segment) and 75th percentile for the nuclear authorized segment.

Question(s):

a) Please provide a listing of the job families that have benchmarking results that are in excess of the 10% variance noted as competitive by WTW.

b) Please explain why OPG views 75th percentile as appropriate for talent attraction and retention for the nuclear authorized segment.

c) How does using the 75th percentile for talent attraction and retention for the nuclear authorized segment impact the relative competitiveness of positions that work with, or supervise, the nuclear authorized employee segment.

F4-Staff-285

Exhibit F4 / Tab 3 / Schedule 1 / pp. 23-24

Preamble:

For benchmarking purposes, OPG previously divided its compensation structure into three segments: Nuclear Authorized, Utility, and General Industry, each with a comparator group.

OPG stated that its difficulty in implementing its broader talent strategy for management positions indicated some tension between its business strategy and its approach to compensation benchmarking. To address this tension, OPG modified its compensation structure to employ two segments: nuclear authorized and non-nuclear authorized (or standard) with each segment having its own comparator group.

Question(s):

a) Please further discuss why implementing its "talent strategy" for management positions required a change to the segmentation used only for compensation benchmarking purposes.

b) Please explain whether WTW believes that the previous three segment methodology or the current two segment methodology leads to more accurate benchmarking results.

c) Please explain whether WTW believes that the current segmentation for benchmarking purposes or the previous segmentation for benchmarking purposes better aligns with best practices.

d) Please advise whether benchmarking results based on the previous three segment methodology is available for any year since OPG's 2017-2021 Payment Amounts application was filed.

e) For comparability to previous compensation benchmarking studies, please provide the 2019 benchmarking results based on the three segments that were previously used and the same compensation data that was provided to WTW. If this is not possible, please explain why.

F4-Staff-286
Exhibit F4 / Tab 3 / Schedule 1 / pp. 29

Preamble:

WTW undertook a comparison of OPG's wages to those provided by Bruce Power.

Question(s):

a) Please confirm that the analysis undertaken includes only base wages (and does not consider any other aspects of compensation).

b) Please advise whether WTW agrees that its Total Compensation Benchmarking Study provides a more comprehensive analysis of OPG's compensation relative to peers in the overall market for skilled labour compared to the WTW Bruce Power wage comparison.

Wilson Towers Watson – Compensation Benchmarking Study

F4-Staff-287
Exhibit F4 / Tab 3 / Schedule 1 / Attachment 2 / p. 3

Preamble:

OEB staff was unable to locate the retainer agreement for the WTW Total Compensation Benchmarking Study (and notes that a retainer agreement was filed for the other independent studies filed in the application).

Question(s):

a) Please file (or provide a reference to) the retainer agreement for the WTW Total Compensation Benchmarking Study.

b) Please confirm that the study only includes employees that work for OPG's regulated nuclear business.

c) Please confirm that the non-nuclear authorized (or total excluding nuclear authorized) segment is essentially the combination of the utility and general industry categories used by WTW for the Total Compensation Benchmarking Study that was filed as part of OPG's 2017-2021 Payment Amounts Proceeding.

F4-Staff-288

Exhibit F4 / Tab 3 / Schedule 1 / Attachment 2 / pp. 5, 28-29

Preamble:

WTW noted that for the total excluding nuclear authorized segment (96% of OPG's population), the comparator group reflects a sample of approximately 75% utility and 25% general industry organizations requiring a large range of skill sets and with an emphasis on large Ontario employers. In addition, the data has been weighted 50% public sector and 50% private sector among the companies in the comparator group.

For the nuclear authorized segment (4% of OPG's population), the comparator group reflects a sample of 10 large nuclear organizations of a comparable size to OPG, including Bruce Power (Canada) and nine U.S.-based nuclear organizations

For pensions and benefits, a single comparator group has been used as organizations typically offer common pension and benefit plans across all roles and skill sets. Pension and benefits data were sourced from WTW's Benefits Data Source (Canada) for a sample of 14 companies reflecting 75% utility and 25% general industry organizations, and 50% public sector and 50% private sector organizations.

Question(s):

a) Please advise whether the selection criteria for determining the peer group has changed since OPG's 2017-2021 Payment Amounts Proceeding. If so, please discuss the changes and provide rationale supporting the changes.

b) Please provide a detailed comparison of the peer group that was used for the utility and general industry segments in the compensation benchmarking filed in OPG's 2017-2021 Payment Amounts Proceeding relative to the peer group that is used for the total excluding nuclear authorized segment in the current proceeding. As part of this response, please discuss which peers were dropped / added and explain why.

c) Please provide rationale supporting the 75% utility / 25% general industry used to generate the peer group for the total excluding nuclear authorized segment benchmarking.

d) Please explain why the peer group for the total excluding nuclear authorized segment is appropriate. As part of this response, please explain why comparing OPG to various oil and gas companies is appropriate.

e) Many of the companies listed in the sample used for the total excluding nuclear authorized segment are neither utility organizations nor Ontario employers (Exhibit F4 / Tab 3 / Schedule 1 / Attachment 2 / pp. 28-29). Please provide a breakdown of comparators by industry and employment market.

f) Please provide rationale supporting the 50% public sector / 50% private sector weighting applied to the data used for the total excluding nuclear authorized segment benchmarking.

g) Please provide a detailed comparison of the peer group that was used for the nuclear authorized segment in the compensation benchmarking filed in OPG's 2017-2021 Payment Amounts Proceeding relative to the peer group that is used for the nuclear authorized segment in the current proceeding. As part of this response, please discuss which peers were dropped / added and explain why.

h) Please explain why only one Canadian nuclear organization is included in the nuclear authorized peer group.

i) Please provide a detailed comparison of the peer group that was used for the pension and benefits benchmarking filed in OPG's 2017-2021 Payment Amounts Proceeding relative to the peer group that is used for pension and benefits benchmarking in the current proceeding. As part of this response, please discuss which peers were dropped / added and explain why.

j) Please provide rationale supporting the 75% utility / 25% general industry used to generate the peer group for the pension and benefits benchmarking.

k) Please provide rationale supporting the 50% public sector / 50% private sector weighting applied to the data used for the pension and benefits benchmarking.

F4-Staff-289
Exhibit F4 / Tab 3 / Schedule 1 / Attachment 2 / pp. 6, 32

Preamble:

WTW noted that for nuclear operations roles that are non-authorized, no direct matches were available in the Canadian market. However, it is recognized that comparable skill sets reside within energy, utility and other general industry organizations. As such, these jobs were matched to total excluding nuclear authorized comparators based on similar skills and level of accountability. Based on a supplemental US analysis, a +10% adjustment was made to the Canadian market statistics for these select roles, reflecting the premium observed in the U.S. market where a critical mass of these skills reside.

Question(s):

a) Please confirm whether this 10% adjustment was applied to only management positions in nuclear operations roles (which do not have licensing requirements) or all positions in nuclear operations roles.

b) Please further discuss the rationale for this adjustment and provide details of the supplemental analysis undertaken by WTW.

c) Please advise whether this same adjustment was made in WTW's compensation benchmarking study filed in OPG's 2017-2021 Payment Amounts Proceeding.

d) Please remove the 10% adjustment and provide the revised benchmarking results. Please highlight which segments / job families are impacted by this adjustment.

F4-Staff-290
Exhibit F4 / Tab 3 / Schedule 1 / Attachment 2 / pp. 7, 33-35

Preamble:

WTW noted that total remuneration includes: (a) total direct compensation; (b) pension & benefits; and (c) paid time off (PTO).

WTW further stated that its standard approach is to exclude PTO values from total remuneration (which is defined in WTW's report as total remuneration excluding PTO). WTW stated that total remuneration including PTO is the primary reference of total remuneration in the report.

Question(s):

a) Please discuss the categories of direct and indirect compensation that OPG provides its employees that are not included in the total remuneration benchmarking. Please provide the value of the excluded compensation as a percentage of the total compensation. Please advise whether WTW believes that including the categories of compensation that have been excluded would have a material impact on the benchmarking results.

b) In the context that WTW's standard approach is to exclude PTO value from total remuneration, please explain why WTW has used total remuneration including PTO as its primary reference.

c) Please confirm that WTW has done numerous compensation benchmarking studies for other organizations where total remuneration excludes PTO.

d) Please confirm that WTW agrees that it is best practice to exclude PTO from total remuneration benchmarking.

e) Please advise whether WTW agrees that the primary reference that the OEB should use in evaluating OPG's compensation benchmarking results is total remuneration excluding PTO as opposed to total remuneration including PTO.

f) Please explain what is meant by regular employer-scheduled holidays and employee scheduled days.

F4-Staff-291
Exhibit F4 / Tab 3 / Schedule 1 / Attachment 2 / p. 8

Preamble:

WTW noted that while OPG continues to believe that 75th percentile is the appropriate market reference for nuclear authorized roles below the executive level, the benchmarking results included in the report summarize OPG's position relative to the 50th percentile for all roles.

Question(s):

a) Please provide WTW's view on whether the 75th percentile or 50th percentile is the appropriate market reference for nuclear authorized roles below the executive level.

F4-Staff-292
Exhibit F4 / Tab 3 / Schedule 1 / Attachment 2 / p. 9

Question(s):

a) Please explain what WTW means by the statement that "the total remuneration values in this report should be interpreted with care and to establish OPG's relative competitiveness against its comparator groups rather than to assess the competitiveness of OPG's costs."

F4-Staff-293
Exhibit F4 / Tab 3 / Schedule 1 / Attachment 2 / p. 10

Question(s):

a) Please provide a summary of the percentage of jobs benchmarked within each job family.
b) Please provide a detailed listing of the positions include within each job family.

F4-Staff-294
Exhibit F4 / Tab 3 / Schedule 1 / Attachment 2 / pp. 13-14

Question(s):

a) Please explain how the performance relative to benchmark (%) for each of the following lines were calculated (e.g. weighted average, etc.):

   i. PWU

   ii. Society

   iii. Management

   iv. OPG Overall

   Please also provide a detailed calculation for OPG Overall performance (%) for base salary, total direct compensation, total remuneration excluding PTO, and total remuneration.

b) Please provide the OPG Overall performance for each of the total excluding nuclear authorized segment and the nuclear authorized segment separately (both excluding and including the Hydro One share grants).

c) Please provide OPG's performance relative to the market for the public sector and private sector separately in the same format as the tables provided at Exhibit F4 / Tab 3 / Schedule 1 / Attachment 2 / pp. 13-14 (both excluding and including the Hydro One share grants).

F4-Staff-295
Exhibit F4 / Tab 3 / Schedule 1 / Attachment 2 / p. 14

Preamble:

WTW noted that annual share grants similar to OPG's Hydro One share grant are relatively uncommon in the market but have been captured in total direct compensation where provided in the market. Other one-time lump sum awards (where in cash or shares) are not captured in WTW's compensation surveys, which could potentially understate the market results.

Question(s):

a) Please further clarify the above statement by providing a table that compares the types of compensation included in OPG's total direct compensation and the types of compensation included in the market's total direct compensation.

b) Please confirm that WTW agrees that the Hydro One share grants are appropriately included in the benchmarking results as those grants are part of the delivered compensation by OPG to its eligible employees.

F4-Staff-296
Exhibit F4 / Tab 3 / Schedule 1 / Attachment 2 / p. 15

Preamble:

WTW noted that included in the analysis are employees with a defined length of employment in the PWU group (i.e. PWU term employees) who do not receive pension and benefits from OPG. These roles have been compared to full-time employees in the market that do receive pension and benefits, as most organizations would be filling these roles with full-time employees.

Question(s):

a) Please further support the statement that other organizations would be filling similar roles with full-time employees that receive pensions and benefits.

b) Please explain why base salary and total direct compensation change from 2019 to 2020 when the difference appears to be that there are more employees that will not receive pensions and benefits from OPG year-over-year.

F4-Staff-297
Exhibit F4 / Tab 3 / Schedule 1 / Attachment 2 / pp. 16, 33-35

Question(s):

a) Please provide a detailed list of what is included in the pension and benefits for OPG and for the comparator group. Please discuss any differences.

b) Please advise if there have been any changes in the methodology used to benchmark pensions and benefits between the WTW's compensation benchmarking study filed in the current proceeding and the compensation benchmarking study filed in OPG's 2017-2021 Payment Amounts Proceeding.

c) If possible, please provide the OPG Overall benchmarking results for each category (pension & benefits, PTO, and entire benefits).

d) Please provide OPG's pension & benefits, PTO and entire benefit values if expressed as a percentage of market base salary rather than actual OPG salary. Please provide the benchmarking results separately for the public sector and private sector.

F4-Staff-298

Exhibit F4 / Tab 3 / Schedule 1 / Attachment 2 / p. 17

Preamble:

WTW noted that overtime is not captured in total remuneration benchmarking as overtime costs are a factor of overtime usage, and usage is not generally captured in compensation surveys. The typical benchmarking approach is to focus on overtime design.

Question(s):

a) Please provide the comparator group that was used for the overtime comparison.

b) Please advise whether WTW is aware of any variances within the comparator group in terms of overtime policies and practices.

c) Please provide a more detailed analysis of the differences between OPG's overtime practices and that of the comparator group.

d) Please discuss the normal work week at OPG relative to the peer group, which forms the basis for overtime comparability analysis. Please explain how the difference, in the normal work week, impacts the overtime analysis.

F4-Staff-299
Exhibit F4 / Tab 3 / Schedule 1 / Attachment 2 / pp. 19-26

Question(s):

a) Please provide alternative versions of all of the benchmarking results by job family inclusive of the Hydro One share grants.

Pensions and Other Post-Employment Benefit Costs

F4-Staff-300
Exhibit F4 / Tab 3 / Schedule 1 / p. 4

Preamble:

The current collective agreements with the PWU and Society end March 31, 2021 and December 31, 2021, respectively.

Question(s):

a) Please explain any assumptions that have been built into the test period actuarial valuations to factor in any anticipated changes in the level of pension and OPEB benefits from the upcoming collective bargaining process. Please provide a table that summarizes the expected impact over the test period.

F4-Staff-301
Exhibit F4 / Tab 3 / Schedule 2 / p. 3
Exhibit F4 / Tab 3 / Schedule 2 / Attachments 1-2

Preamble:

Chart 1 at Exhibit F4 / Tab 3 / Schedule 2 / p. 3 shows the total pension and OPEB accrual costs, which were determined by Aon as set out in Attachments 1-2 of Exhibit F4 / Tab 3 / Schedule 2.

Question(s):

a) Please provide a table that reconciles the 2020 to 2026 accrual amounts in Chart 1 to the “Estimated Employer Pension Contributions / Benefit Payments” line in Schedules 3A to 3G of the Aon Report in Attachment 1.

b) Please explain the correlation between the pension and OPEB accrual amounts in Chart 1 and the Estimated Employer Pension Contributions / Benefit Payments. Please include a discussion on the correlation between the two for 2025 and 2026.

F4-Staff-302

Exhibit F4 / Tab 3 / Schedule 2 / p. 3
Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1
Exhibit F4 / Tab 4 / Schedule 1 / Table 3
Exhibit A2 / Tab 1 / Schedule 1 / Attachment 2 / pp. 14-15

Preamble:

Chart 1 at Exhibit F4 / Tab 3 / Schedule 2 / p. 3 shows the total pension and OPEB accrual costs.

In OPG's 2019 AFS, under New Accounting Standards effective in 2018 regarding net periodic post-retirement benefit cost, it states:

> Effective January 1, 2018, OPG adopted the new provisions of Topic 715. Adoption of these provisions did not impact OPG and the Prescribed Facilities' financial statements, as OPG capitalized only the service cost component of post retirement benefits costs prior to the adoption of the new guidance.

Question(s):

a) For each of pension and OPEBs, please provide a breakdown of the amounts capitalized, the amounts included in nuclear compensation, and the amounts included in centrally held costs.

b) Please also reconcile these amounts to those included in nuclear compensation in Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1 and to those included in centrally held costs in Exhibit F4 / Tab 4 / Schedule 1 / Table 3.

c) Please explain how OPG determines capitalized pension and OPEB amounts.

d) Regarding the statement referenced above from the 2019 AFS, please confirm that the statement is applicable to the capitalized pension and OPEB costs included in the application.

e) If not confirmed, please explain how the adoption of Provision 715 impacted OPG's treatment for capitalizing pension and OPEB costs for regulatory purposes.

F4-Staff-303

Exhibit F4 / Tab 3 / Schedule 2 / p. 3

Preamble:

Chart 1 at Exhibit F4 / Tab 3 / Schedule 2 / p. 3 shows the total pension and OPEB accrual costs.

a) For the 2016 to 2020 period, please provide a table comparing forecasted pension and OPEB accrual costs in OPG's 2017-2021 Payment Amounts Proceeding to the actual pension and OPEB accrual costs shown in Chart 1 at Exhibit F4 / Tab 3 / Schedule 2 / p. 3.

b) If the 2021 to 2026 pension and OPEB accrual costs were forecasted in a past OPG proceeding, please provide a table comparing this prior forecast to the current forecast shown in Chart 1 at Exhibit F4 / Tab 3 / Schedule 2 / p. 3.

c) For the tables provided in response to parts (a) and (b) above, please discuss the reasons for the differences presented in those tables.

F4-Staff-304

Exhibit F4 / Tab 3 / Schedule 2 / p. 3

Preamble:

Chart 1 at Exhibit F4 / Tab 3 / Schedule 2 / p. 3 shows the pension and OPEB accrual costs for the 2016 to 2026 period. OPG stated that both pension and OPEB accrual costs decline toward the end of the Custom IR term due to the planned Pickering NGS shutdown and associated reduction in the workforce.

Question(s):

a) Please discuss how the planned Pickering NGS shutdown will affect the various components of pension and OPEB accrual costs.

b) Please discuss how the planned Pickering NGS shutdown has been specifically accounted for in the pension and OPEB accrual costs. Please discuss the assumptions that reflect the impact from the planned Pickering NGS shutdown.

c) Please explain whether any forecasted to actual pension and OPEB accrual costs difference is proposed to be recorded in the Pickering Closure Costs Deferral Account.

F4-Staff-305
Exhibit F4 / Tab 3 / Schedule 2 / p. 3

Question(s):

a) Regarding pension and OPEB accrual costs, please provide a sensitivity analysis in table form on the pension and OPEB-related 2022-2026 revenue requirements for the following management assumptions:

   i. Inflation rate - show the impact of an increase / decrease of 0.25%

   ii. Discount rate – show the impact of an increase / decrease of 0.25%

   iii. Expected long-term rate of return - show the impact of an increase / decrease of 0.25%

   iv. Salary Increases return - show the impact of an increase / decrease of 0.25%

   v. Health care cost trend rate - show the impact of an increase / decrease of 1.00%

F4-Staff-306
Exhibit F4 / Tab 3 / Schedule 2 / p. 8
Exhibit F4 / Tab 3 / Schedule 2 / Attachment 1 / p. 8

Preamble:

OPG stated in Footnote 15 at Exhibit F4 / Tab 3 / Schedule 2 / p. 8 that for the purpose of projecting pension and OPEB costs, OPG may adjust discount rate assumptions from those provided by its independent actuary by a maximum of 25 basis points.

In the Aon Report at Page 8 of Exhibit F4 / Tab 3 / Schedule 2 / Attachment 1 / p. 8, Aon stated that “Other actuarial assumptions are management’s best estimate of future events, as determined in consultation with us and as set out in the Reports”. These assumptions include the inflation rate and salary scale increase rates.

Question(s):

a) Other than the discount rate, please identify the assumptions used in determining pension and OPEB costs, where OPG applied any discretion or judgement in quantifying the assumption.

b) For the assumptions identified in part (a), please discuss the degree of discretion and judgement OPG applied in quantifying the assumption.

F4-Staff-307
Exhibit F4 / Tab 3 / Schedule 2 / p. 6

Preamble:

OPG stated that many of the pension assumptions used for accounting purposes are the same as those used in the actuarial valuations for funding purposes.

Question(s):

a) Please identify the pension assumptions used for accounting purposes that differ from those used in the actuarial valuations, please identify the assumptions.

b) For each of the assumptions identified in part (a), please explain why a different assumption was used for accounting purposes and what the impact of that has on the accrual costs.

F4-Staff-308
Exhibit F4 / Tab 3 / Schedule 2 / p. 3
Exhibit F4 / Tab 3 / Schedule 2 / p. 18

Preamble:

OPG stated that forecast OPEB payments for the 2022-2026 period represent the total estimated future cash flows used by Aon to project OPEB benefit obligations over this period, as attributed to the nuclear facilities.

Question(s):

a) Please explain whether the OPEB assumptions used in determining the accrual costs as presented in Chart 1 at Exhibit F4 / Tab 3 / Schedule 2 / p. 3 differ from those used in the estimated future cash flows used by Aon to project OPEB benefit obligations.

b) If so, please identify each assumption, and for each of the assumptions, please explain why a different assumption was used for accounting purposes and what the impact of that has on the accrual costs.

F4-Staff-309
Exhibit F4 / Tab 3 / Schedule 2 / p. 9
Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1

Preamble:

Chart 4 at Exhibit F4 / Tab 3 / Schedule 2 / p. 9 shows the assumptions OPG used to determine pension and OPEB accrual costs.

Question(s):

a) The expected long-term rate of return on pension fund assets is 6% for the 2016 to 2026 period. Please explain why there has been no change to the rate for the ten-year period.

b) Please further explain the 1.7% weighted average salary schedule escalation rate for the January 1, 2020 to December 31, 2026 period. Please advise whether this escalation rate is reflected in the compensation costs shown at Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1.

F4-Staff-310
Exhibit F4 / Tab 3 / Schedule 2 / pp. 11 – Chart 5, 13, 14 – Chart 6
Exhibit F4 / Tab 4 / Schedule 1 / Table 3
Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1

Preamble:

The below question uses 2026 as an example but applies to all years from 2016 to 2026.

Chart 5 at Exhibit F4 / Tab 3 / Schedule 2 / p. 11 provides the components of pension and OPEB costs allocated to the business unit charge and centrally held costs. For 2026, $239.7 million of accrual costs are allocated to the business unit charge and ($56.2) million of accrual costs are allocated to centrally held costs, totaling $183.5 million of pension and OPEB accrual costs.

Chart 6 at Exhibit F4 / Tab 3 / Schedule 2 / p. 14 provides the current service cost component of pension and OPEB accrual costs. For 2026, the current service charge relating to direct charge is $239.7 million and the current service charge relating to centrally held costs is $35.4 million, totaling $275.2 million of current service charge.

Question(s):

a) OPG stated that total current service cost is comprised of estimated amounts charged to the business units through standard labour rates as well as variances from these estimated amounts, which are included in centrally held costs. For 2026, total nuclear pension and OPEB costs as shown in Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1 / Line 51 are $275.2 million. This agrees with the current service charge in Chart 6 at Exhibit F4 / Tab 3 / Schedule 2 / p. 14. However, this includes $35.6 million of centrally held costs. Please clarify if the current service costs for centrally held costs should be included in total nuclear compensation or centrally held costs.

b) Per Chart 5 at Exhibit F4 / Tab 3 / Schedule 2 / p. 11, ($56.2) million is included in centrally held costs as shown in Exhibit F4 / Tab 4 / Schedule 1 / Table 3. Per Chart 6 Exhibit F4 / Tab 3 / Schedule 2 / p. 14, $275.2 million (including $35.6 million of current service charge costs for Centrally Held Costs) have been included in nuclear compensation as shown in Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1 / Line 51. The total included in centrally held costs and nuclear compensation is $219 million ($275.2 million – $56.2 million). Total 2026 pension and accrual costs as shown in Chart 5 at Exhibit F4 / Tab 3 / Schedule 2 / p. 11 are $183.5 million. Please reconcile the difference between the accrual amounts included in centrally held costs and nuclear compensation to that as shown in the total of Chart 5 at Exhibit F4 / Tab 3 / Schedule 2 / p. 11. Please also explain the treatment of current service cost for centrally held costs and whether it is included in centrally held costs and / or nuclear compensation.

F4-Staff-311
Exhibit F4 / Tab 3 / Schedule 2 / Attachment 1 / p. 8
Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1

Question(s):

a) On page 8 of Exhibit F4 / Tab 3 / Schedule 2 / Attachment 1, active headcounts for nuclear and support services are provided. Please explain and reconcile the difference in headcounts between Exhibit F4 / Tab 3 / Schedule 2 / Attachment 1 / p. 8 and Exhibit F4 / Tab 3 / Schedule 1 / Attachment 1. Please discuss the differences between the two noted attachments, and specifically discuss the correlation between the two for 2025 and 2026.

F4-Staff-312
Exhibit F4 / Tab 3 / Schedule 2 / Attachment 1 / p. 9

Preamble:

Page 9 of Exhibit F4 / Tab 3 / Schedule 2 / Attachment 1 states:

> For 2020, the projected benefit payments reflect actual experience up to June 30, 2020. We observed a decrease in health and dental claims during the first six months of 2020 due to changes in claim patterns resulting from the emergence of the COVID-19 pandemic. Given the unprecedented nature of this event and the evolving course of the contagion, we do not believe that the potential impact of these patterns on longer-term projections can be reasonably extrapolated at the present time. For this reason, we have not recommended any changes to assumptions used in the projections in this report.

Questions:

a) Aside from the decrease in health and dental claims during the first six months of 2020, are there any other impacts due to the COVID-19 pandemic that would have an impact on OPG's pension and OPEB costs?

b) If so, please identify them and explain how they would impact OPG's pension and OPEB costs. Please also explain how OPG proposes to treat these impacts for regulatory purposes.

c) Please quantify the impact to pension and OPEB accrual costs for the prescribed facilities if the impact(s) from the COVID-19 pandemic were taken into account.

F4-Staff-313
Exhibit F4 / Tab 3 / Schedule 2 / Attachment 3 / p. 7

Preamble:

On page 7 of Exhibit F4 / Tab 3 / Schedule 2 / Attachment 3, Aon stated:

> Due to the COVID-19 pandemic, the financial markets experienced significant volatility after the valuation date. As with other experience emerging after the valuation date, any financial impact of this event on the Plan will be reflected in the next actuarial valuation report.

Question(s):

a) Please confirm that the impact of the COVID-19 pandemic is not expected to impact OPG's funding requirements until its next actuarial valuation expected in 2023.

b) If not confirmed, please explain how the impact of the COVID-19 pandemic may impact OPG's funding requirements. Please quantify the impact and explain how OPG plans on treating this impact for regulatory purposes.

Centrally Held Costs

F4-Staff-314
Exhibit F4 / Tab 4 / Schedule 1 / p. 7

Question(s):

a) Please further discuss how OPG forecasted OPG-wide and nuclear insurance costs for the 2022-2026 Custom IR term.

b) Please confirm that the combined OPG-wide and nuclear insurance costs were $26.4 million less than OEB-approved in aggregate during the 2017-2021 period.

F4-Staff-315
Exhibit F4 / Tab 4 / Schedule 1 / Tables 1, 3

Question(s):

a) Please advise whether Table 1 at Exhibit F4 / Tab 4 / Schedule 1 includes only centrally held costs associated with the regulated business (both nuclear and hydroelectric) or both the regulated and unregulated businesses.
b) Please provide a breakdown by cost category (e.g. ONFA fee, fiscal calendar adjustment, etc.) of the "other" line in both Tables 1 and 3 at Exhibit F4 / Tab 4 / Schedule 1.

F4-Staff-316
Exhibit F4 / Tab 4 / Schedule 1 / p. 6
Exhibit F4 / Tab 4 / Schedule 1 / Table 3

Preamble:

OPG explained that the fluctuations in IESO Non-Energy Charges are primarily due to the Global Adjustment (GA).

Question(s):

a) Please explain why OPG is forecasting an increase of over $10 million in 2024 relative to 2023 (from $89.4 million to $99.9 million).

F4-Staff-317
Exhibit F4 / Tab 4 / Schedule 2 / Table 2a

Question(s):

a) Please confirm that the adjustment to pension / OPEB for test period cash to accrual differences (Line 2 at Exhibit F4 / Tab 4 / Schedule 2 / Table 2a) makes the comparison between the total actual centrally held costs and the OEB-approved costs not meaningful.

b) Please provide a revised version of Table 2a at Exhibit F4 / Tab 4 / Schedule 2 excluding pensions / OPEB-related accrual costs and the adjustment. Please also provide the aggregate 2017-2021 OEB-approved amounts and the aggregate actual centrally held costs (excluding pensions / OPEB and the related adjustment). Please provide a discussion of the major driver(s) for the aggregate variance over the 2017-2021 period.

c) Please provide a breakdown by cost category (e.g. ONFA fee, fiscal calendar adjustment, etc.) of the “other” line for OEB-approved and actual in Table 2a at Exhibit F4 / Tab 4 / Schedule 2.

Exhibit G2 – Nuclear Other Revenues

Bruce Generating Stations – Revenues and Costs

G2-Staff-318
Exhibit G2 / Tab 2 / Schedule 1 / pp. 1, 3

Preamble:

OPG stated that Bruce Power has options to renew the lease to December 31, 2064. OPG’s Custom IR term forecasts assume that Bruce Power will exercise its options to renew the lease.

Question(s):

a) Please advise when the Bruce Lease is set to expire.

b) Please advise whether there are any expected changes to the Bruce Lease at the time of the renewal that may impact the Bruce Lease net revenues incorporated as part of OPG’s proposed 2022-2026 revenue requirements.

c) Please further explain why the full amount of base rent is considered an executory cost (effective 2019).

d) Please provide the calculation supporting the Bruce Lease base rent revenues for 2022-2026.

G2-Staff-319
Exhibit G2 / Tab 2 / Schedule 1 / Tables 1, 5
Exhibit F4 / Tab 2 / Schedule 1 / Table 3c

Preamble:

OEB staff notes that OPG included deferred tax (Line 10 at Exhibit G2 / Tab 2 / Schedule 1 / Table 5) in the computation of Bruce costs for the 2016-2026 period. The Bruce net revenues form part of OPG's calculation of regulatory income tax at Exhibit F4 / Tab 2 / Schedule 1 / Table 3c.

OEB staff also notes that OPG's income tax expense for prescribed facilities is based on the taxes payable method (i.e. excludes the impact of deferred taxes).
Question(s):

a) Please provide rationale for departing from the taxes payable method in calculating Bruce net revenues and why it is appropriate to apply a different basis for calculating taxes than the one used for OPG's prescribed facilities.

b) Is OPG aware of any prior OEB decisions where the OEB approved the inclusion of deferred tax impacts in the determination of Bruce net revenues? If so, please provide reference to those decisions.

Exhibit H1 – Deferral and Variance Accounts

H1-Staff-320
Exhibit H1 / Tab 1 / Schedule 1

Question(s):

a) Please confirm that OPG has the 2020 year-end deferral and variance account balances available. If so, please provide those balances on the record of the current proceeding.

b) Please provide OPG's position on including the 2020 deferral and variance account balances in the disposition sought in the current proceeding.

c) If the 2020 balances are not disposed in the current proceeding, please advise when OPG intends to seek disposition.

H1-Staff-321
Exhibit H1 / Tab 1 / Schedule 1 / pp. 1-2
Exhibit H1 / Tab 2 / Schedule 1 / Tables 1-2

Preamble:

OPG stated that adjusted for 2020-2021 amortization amounts approved in previous proceedings, the proposed balances recoverable in this application are a net debit balance of $141.3 million for the regulated hydroelectric facilities and a net debit balance of $339.8 million for the nuclear facilities.

Question(s):

a) Please confirm that inclusive of tax impacts on Pension & OPEB Cash Versus Accrual Differential Deferral Account OPG is seeking recovery of $178.8 million for the regulated hydroelectric facilities and $565.2 million for the nuclear facilities. Please also confirm that these are the amounts that will be recovered through the proposed rate riders.

H1-Staff-322
Exhibit H1 / Tab 1 / Schedule 1 / pp. 8-9

Preamble:

The reference above describes the computation of deviations of actual monthly flows from historical median monthly flows.

Question(s):

a) Please clarify why monthly production forecasts for 2015 are used to calculate deviations for January 1 to June 30 of each year, while the average of corresponding monthly production forecasts for 2014 and 2015 is used to calculate deviations for July 1 to December 31 of each year.

H1-Staff-323
Exhibit H1 / Tab 1 / Schedule 1 / p. 8

Question(s):

a) Please confirm that the methods used to calculate deviations in energy production due to actual water flows (and associated financial impact) are the same as those approved in OPG’s 2017-2021 Payment Amounts Proceeding. If not, please explain.

H1-Staff-324
Exhibit H1 / Tab 1 / Schedule 1 / p. 8

Question(s):

a) Please clarify what is meant by “calculated actual” and how it is different from actual, if at all.

b) Please explain why calculated actual is used instead of actual? Please advise whether it is to isolate the impact of actual flow / water conditions on production.

H1-Staff-325
Exhibit H1 / Tab 1 / Schedule 1 / pp. 11-12

Preamble:

OPG described how it calculates forgone production due to SBG.

Question(s):

a) Please confirm that the method for calculating forgone production due to SBG is the same as used in OPG’s 2017-2021 Payment Amounts Proceeding. If not, please explain.

b) Please clarify why OPG excludes spill that occurs when the Ontario market price is above the level of the Gross Revenue Charge in determining the foregone production due to SBG.

H1-Staff-326
Exhibit H1 / Tab 1 / Schedule 1 / pp. 14-16
Exhibit H1 / Tab 1 / Schedule 1 / Table 6

Preamble:

OPG provided the 2018 and 2019 entries in the Income and Other Taxes Variance Account in Table 6 at Exhibit H1 / Tab 1 / Schedule 1.

OPG explained the four entries recorded in the Income and Other Taxes Variance Account for 2018 and 2019 as follows:

- A credit entry in 2019 related to a CCA rule change, which provides for a first-year increase in CCA deductions on eligible capital assets acquired after November 20, 2018. As per the OEB's letter dated July 25, 2019 discussed below, this entry was recorded in a separate sub-account.

- A credit entry related to an increase in the recognition of SR&ED ITCs for the 2014 taxation year from 75% to 100%, based on the resolution of the 2014 income tax audit in 2018.
- A credit entry related to an increase in the recognition of SR&ED ITCs for the 2015 taxation year from 75% to 100%, based on the resolution of the 2015 income tax audit in 2019.

- A debit entry related to a reduction to the rate for the Ontario Research and Development Tax Credit (reported as part of SR&ED ITCs) from 4.5% to 3.5% of qualifying expenditures, effective June 1, 2016. The entry applies to the regulated hydroelectric facilities only, as the impact of this change for the nuclear facilities was already reflected in the 2017-2021 nuclear revenue requirements.

OPG further stated that for the nuclear facilities, the CCA-related entry was calculated by applying the new CCA rules to the forecast capital additions for the eligible period and resulting undepreciated capital cost balances (other than those for DRP and any other CRVA-eligible projects) reflected in the approved 2017-2021 nuclear revenue requirements, holding other variables constant. For the regulated hydroelectric facilities, OPG applied the new accelerated CCA rules to the forecast capital additions reflected in the approved 2014-2015 regulated hydroelectric revenue requirements, using percentage eligible of actual regulated hydroelectric projects (for the corresponding year) as a proxy.

Question(s):

a) Please explain why the SR&ED ITCs recognition percentages have increased from 75% to 100% for the 2014 and 2015 taxation years, following their respective audits.

b) Please provide the summary pages of the 2014 and 2015 income tax audit reports.

c) Please explain why the addition to the variance account of $0.1 million in 2018 due to the increase of SR&ED ITCs recognition percentage from 75% to 100% for regulated hydroelectric is a debit.

d) Please provide the supporting 2019 CCA difference calculations for:

   i. Hydroelectric ($7.0 million)

   ii. Nuclear ($28.8 million)

e) Please explain the method used by OPG to prorate the CCAs after November 20, 2018 for the calculation of the 2018 CCA differences.

f) Please provide the calculation of the full revenue requirement impact of the CCA changes using the approved capital additions in OPG's 2017-2021 Payment Amounts Proceeding. Please update the full revenue requirement impact of the CCA changes in the account by including the 2020 balance.

g) From a cash flow perspective, what are the benefits that OPG has realized from CCA deductions under the AIIP in 2018, 2019 and 2020? Please provide the associated calculation of the benefits using the actual eligible capital additions in 2018, 2019 and 2020.

H1-Staff-327
Exhibit H1 / Tab 1 / Schedule 1 / p. 18

Preamble:

OPG stated that it is not seeking clearance of the hydroelectric balances in the CRVA in this application. OPG proposed to defer such clearance 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 2017-2021 IR period.

Question(s):

a) Please provide the total hydroelectric balance in the CRVA to December 31, 2019 (including a breakout of the CCA rule change impact) and provide a brief discussion of the drivers for the balance in the account.

b) Please advise whether OPG intends to seek recovery of the hydroelectric balance in the CRVA starting in 2027.

H1-Staff-328
Exhibit H1 / Tab 1 / Schedule 1 / p. 19

Preamble:

OPG stated that there are three nuclear CRVA-eligible projects included in the proposed revenue requirements in the current application as follows:

- Pickering Optimized Shutdown
- Fuel Channel Life Extension
- Fuel Channel Life Extension Ongoing Costs

Question(s):

a) Please confirm that the DRP is also eligible and has revenue requirement amounts during the 2022-2026 Custom IR term.

b) Please provide the proposed annual revenue requirements for each of the nuclear CRVA-eligible projects and confirm that these will be the reference amounts to which any variance will be recorded (if approved as filed).

H1-Staff-329
Exhibit H1 / Tab 1 / Schedule 1 / p. 19

Preamble:

OPG stated that it is proposing to defer the clearance of a debit balance of $51.4 million related to the DRP as at December 31, 2019 to a future application.

Question(s):

a) Please confirm that the deferred DRP-related amount was updated to $55.6 million in the corrected evidence.

b) Please provide the detailed calculations supporting this amount and please provide the drivers for this amount.

c) Please advise whether OPG expects to seek disposition of the DRP-related CRVA balances starting in 2027.

H1-Staff-330
Exhibit H1 / Tab 1 / Schedule 1 / pp. 19-20
Exhibit H1 / Tab 1 / Schedule 1 / Table 1b

Preamble:

OPG proposed to clear, in full, the DRP-related credit balance of $19.2 million, as at December 31, 2019, for the impact of the CCA rule changes. This amount was calculated by applying the new CCA rules to the forecast DRP capital additions for the eligible period and resulting undepreciated capital cost balances reflected in the approved 2017-2021 revenue requirements, holding other variables constant.

OEB staff notes that the $19.2 million credit balance is comprised of a $18.9 million transaction booked in 2019 and $0.3 million of interest.

Question(s):

a) Please provide the calculation supporting the $18.9 million revenue requirement impact booked in 2019.

H1-Staff-331
Exhibit H1 / Tab 1 / Schedule 1 / p. 21
Exhibit H1 / Tab 1 / Schedule 1 / Table 15

Preamble:

OPG noted that, as part of the 2019 non-capital entries in the CRVA, it recorded a debit adjustment of $24.0 million related to the reference plan amount against which variances in the Fuel Channel Life Extension Project costs were being determined since June 1, 2017. The adjustment was made to correct an error made by OPG in the draft payment amounts order submission in OPG's 2017-2021 Payment Amounts Proceeding, which was subsequently reproduced in the final Payment Amounts Order.

OPG referenced a number of exhibits from OPG's 2017-2021 Payment Amounts Proceeding to highlight where the error occurred.

Question(s):

a) Please file the referenced exhibits on the record of the current proceeding and describe how the error occurred.

b) Please confirm that Note 4 at Exhibit H1 / Tab 1 / Schedule 1 / Table 15 provides the detailed calculation for the adjustment made to correct for the error.

H1-Staff-332
Exhibit H1 / Tab 1 / Schedule 1 / Table 15

Question(s):

a) Please further explain Note 3 in the corrected version of Exhibit H1 / Tab 1 / Schedule 1 / Table 15.

b) Please explain the changes made to Lines 22 and 28 at Exhibit H1 / Tab 1 / Schedule 1 / Table 15 in the corrected evidence.

c) Please explain all the changes made to Note 1 in the corrected evidence.

d) Note 6 states that 2016 includes a catch up of $3.1 million relating to 2015 spending on Darlington Spacer Retrieval Tooling Project that was not previously recorded in the CRVA. Please explain why this amount was not previously recorded and why it is appropriate to record this amount in the current proceeding.

e) Note 7 states that the Pickering Extended Operations actual non-capital costs include $1.2 million related to a non-CRVA eligible project that was inadvertently booked to the account in 2017. OPG noted that this amount will be corrected in 2020 (inclusive of all interest as of the original date of booking). Please explain why OPG is not proposing to make this adjustment as part of the disposition requested in the current proceeding.

H1-Staff-333
Exhibit H1 / Tab 1 / Schedule 1 / p. 23

Question(s):

a) Please confirm that no further balances will be recorded to the Pension and OPEB Cost Variance Account.

b) Please confirm that after the remaining approved amounts recorded in the Pension and OPEB Cost Variance Account are disposed, the account can be closed.

H1-Staff-334
Exhibit H1 / Tab 1 / Schedule 1 / p. 34

Question(s):

a) Please provide an estimate of the expected costs to be incurred over the 2022-2026 period related to the CNSC Fitness for Duty program and advise if OPG expects to seek recovery of this balance starting in 2027.

H1-Staff-335
Exhibit H1 / Tab 1 / Schedule 1 / p. 35
Exhibit H1 / Tab 1 / Schedule 1 / Table 14

Preamble:

OPG stated that actual SR&ED ITCs net of tax (attributed to the nuclear facilities) recorded in 2018 and 2019, inclusive of the immediately preceding year's true-up adjustments based on tax return completion, were higher than the forecast amounts reflected in the corresponding revenue requirements approved in OPG's 2017-2021 Payment Amounts Proceeding.

OPG provided the summary of transactions that are recorded in the account for 2018 and 2019.

Question(s):

a) Please explain if OPG had undergone any audits for 2016 and subsequent years of the SR&ED ITCs. If so, please provide any findings from those audits.

H1-Staff-336
Exhibit H1 / Tab 1 / Schedule 1 / pp. 35-37
Exhibit H1 / Tab 1 / Schedule 1 / Table 13

Preamble:

OPG provided the derivation of the 2018 and 2019 entries in the Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account in Table 13 at Exhibit H1 / Tab 1 / Schedule 1. OEB staff notes that OPG did not request the clearance of the 2020 and 2021 revenue requirement impacts that are also presented in the above noted table.
Question(s):

a) Please explain whether the 2020 and 2021 revenue requirement impacts as set out in Table 13 are subject to change. If so, please provide the components of the revenue requirements that are subject to change for those years and provide the reasons for the potential changes.

H1-Staff-337
Exhibit H1 / Tab 1 / Schedule 1 / pp. 38-41

Preamble:

OPG proposed the establishment of the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account to record the revenue requirement impacts from the change of the EOL dates for Pickering NGS Units 1 and 4 and Pickering NGS Units 5-8.

OPG stated that it is not able to provide the total revenue requirement impact associated with the changes being implemented as of December 31, 2020 at this time, primarily because the final year-end information required to calculate the December 31, 2020 ARO / ARC adjustment is not yet available. Accordingly, these changes are not reflected in OPG's application.

On January 20, 2021, the OEB issued an interim order approving the establishment of the Impact Resulting from Optimization of Pickering Station End-of-Life Dates Deferral Account as OPG stated that the revenue requirement impact of the revision to the Pickering NGS EOL dates commences January 1, 2021.

Question(s):

a) Please provide the revenue requirement impact and the associated calculations for the components of the revenue requirement impact for the EOL dates change for Pickering NGS Units 1 and 4.

b) Please provide the revenue requirement impact and the associated calculations for the components of the revenue requirement impact for the EOL dates change for Pickering NGS Units 5 to 8.

c) Please provide the entries that OPG has recorded and expects to record in this account in 2021.

H1-Staff-338
Exhibit H1 / Tab 1 / Schedule 1 / Table 8
OPG 2019 Annual Report[18] / p. 1

Preamble:

OPG provided the regulated hydroelectric actual production in Table 8 at Exhibit H1 / Tab 1 / Schedule 1.

OEB staff notes that the 2018 annual actual hydroelectric production set out in OPG's 2019 Annual Report is 29.8 TWh. The 2019 annual actual hydroelectric production set out in OPG's 2019 Annual Report is 30.5 TWh

OEB staff compiled the actual hydroelectric production for 2018 and 2019 based on the application and OPG's 2019 Annual Report in the table below:

(TWh)	**2019**	**2018**	**2018 (10 months)**
2019 Annual Report	30.5	29.8	24.8[19]
Table 8	30.6		24.5
Difference	**0.1**		**-0.3**

Question(s):

a) Please explain the 2019 variance of 0.1 TWh between OPG's 2019 annual report and Table 8 at Exhibit H1 / Tab 1 / Schedule 1.

[18] https://www.opg.com/reporting/financial-reports/.
[19] OEB staff prorated the annual 2018 production amount for a 10-month period.

b) Please advise whether the 10-month data that OPG uses in Table 8 for 2018 is based on actuals for March 1, 2018 to December 31, 2018 or is based on a proration of the annual production for the noted 10-month period. If a proration approach is used, please explain the variance (-0.3 TWh).

H1-Staff-339

Exhibit H1 / Tab 2 / Schedule 1 / pp. 2-4

Preamble:

With respect to the recovery period of the DVAs, OPG stated that with the exception of components of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the portion of the Bruce Lease Net Revenues Variance Account – Non-Derivative Sub-Account approved in OPG's 2019 Annual Update and Deferral Account Disposition proceeding[20], OPG proposed to recover the DVA account balances, on a straight-line basis, over the three-year period January 1, 2022 to December 31, 2024.

OPG stated the recovery period of Bruce Lease Net Revenues Variance Account – Non-Derivative Sub-account reflected the approved amortization period in OPG's 2019 Annual Update and Deferral Account Disposition proceeding.[21]

OPG stated that it proposes to align the recovery period for the EB-2018-0243 Registered Pension Plan component (and its associated income tax impacts) and the Post-2017 Additions component (and its associated income tax impacts) of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, to the full January 1, 2022 to December 31, 2026 term. The resulting five-year recovery period would be close to the six-year recovery period for the EB-2018-0243 Non-Registered Pension Plan component.

Question(s):

a) Please explain why OPG is proposing to align the recovery period (five years) of the Pension & OPEB Cash Versus Accrual Differential Deferral Account components referenced above to close to the six-year recovery period for the EB-2018-0243 Non-Registered Pension Plan component.

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[20] EB-2018-0243.

[21] Exhibit H1 / Tab 2 / Schedule 1 / Table 2 / Line 10 / Column (f). The total approved recovery period of eight years from January 1, 2019 to December 31, 2026 is per EB-2018-0243 / Exhibit / M1 / Attachment A / Table 2 / Line 8.

b) Please provide OPG's position on recovering the Pension & OPEB Cash Versus Accrual Differential Deferral Account components over a three-year period, consistent with the recovery period of other DVAs.

c) Please provide a bill impact comparison between the five-year recovery period and the three-year recovery period for the Pension & OPEB Cash Versus Accrual Differential Deferral Account EB-2018-0243 Registered Pension Plan component and the Post-2017 Additions component.

H1-Staff-340
Exhibit H1 / Tab 2 / Schedule 1 / Table 2

Question(s):

a) Please reconcile the updated column (b) in Exhibit H1 / Tab 2 / Schedule 1 / Table 2 to the Payment Amount Order in OPG's 2017-2021 Payment Amounts Proceeding. Please explain any differences.

Exhibit I1 – Determination of Payment Amounts

Revenue Requirement Work Form

I1-Staff-341
Exhibit I1 / Tab 1 / Schedule 1 / Attachment 1

Question(s):

a) Upon responding to all interrogatories, please provide an updated Revenue Requirement Work Form (RRWF) in working Microsoft Excel format with any corrections or adjustments that OPG wishes to make to the amounts in the populated version of the RRWF filed. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note.

Consumer Impact

I1-Staff-342
Exhibit I1 / Tab 1 / Schedule 2 / Tables 1-2

Preamble:

OEB staff notes that there is a $0.27 bill impact in 2024. In 2024, the hydroelectric payment amount (including riders) is unchanged and the nuclear payment (including riders) decreases relative to 2023.

Question(s):

a) Please confirm that the bill impact in 2024 is driven by relatively more of OPG's overall production being generated by the nuclear generating stations than the prior year.

Payment Amount Smoothing

I1-Staff-343
Exhibit I1 / Tab 3 / Schedule 2 / p. 6

Question(s):

a) Please provide the calculations supporting the 2027-2031 and 2032-2036 anticipated revenue requirements. Please discuss whether deferral account dispositions are considered in the rate smoothing analysis.

I1-Staff-344
Exhibit I1 / Tab 3 / Schedule 2 / pp. 8, 15
Exhibit I1 / Tab 1 / Schedule 2 / Tables 1-2

Preamble:

OPG provided a chart highlighting the impact of its rate smoothing proposal (relative to four alternatives) on a number of relevant indicators in Chart 3 at Exhibit I1 / Tab 3 / Schedule 2 / p. 8.

Question(s):

a) For each alternative (A-D), provide the same information as is provided in Chart 4 at Exhibit I1 / Tab 3 / Schedule 2 / p. 15.

b) Please advise whether the total interest line reflects the total amount of interest that will be paid by ratepayers to the end of the Rate Smoothing Deferral Account (RSDA) disposition period. Please confirm that OPG expects that the RSDA balance will be fully disposed by the end of 2036.

c) Please provide a detailed calculation supporting the interest cost / deferred revenue ratio for each alternative.

d) Please confirm that the nuclear payment amount transition impact post-2036 is measuring the expected bill impacts between 2036 and 2037.

e) Please provide the same information as is provided in Charts 3 and 4 at Exhibit I1 / Tab 3 / Schedule 2 / pp. 8, 15 for the following alternatives:

   i. No deferred revenue requirement during the 2022-2026 Custom IR term.

   ii. Deferring the proposed $241.2 million of revenue requirement in 2022 but no deferred revenue requirement in any other years of the 2022-2026 Custom IR term.

   iii. Ensuring that the total interest costs do not exceed $500 million (to the end of the disposition period – Line 5 in Chart 3 at Exhibit I1 / Tab 3 / Schedule 2 / p. 8) and deferring revenue requirement in a manner that minimizes year-over-year changes in bill impacts.

f) Please provide the average annual bill impact tables in the same format as Exhibit I1 / Tab 1 / Schedule 2 / Tables 1-2 for the 2022-2026 period for each of the alternative rate smoothing options (and the additional alternatives that OEB staff has requested in part (e)).

I1-Staff-345
Exhibit I1 / Tab 3 / Schedule 2 / pp. 8-13

Question(s):

a) Please confirm that it is Alternatives A-C that fail the financial viability metrics.

b) Please confirm that none of OEB staff's requested alternatives fail the financial viability metrics.

c) Please explain why OPG believes that having higher bill impacts in 2022 (relative to the remainder of the 2022-2026 Custom IR term) is optimal from a rate stability perspective.

d) Please advise whether customers that participated in the customer engagement activities related to rate smoothing were made aware of the magnitude of the interest costs they would be required to pay to implement rate smoothing.

Appendix A

Authorized Return on Equity for Canadian and U.S. Gas and Electric Utilities, Volume V, May 25, 2017 (revised)

Authorized Return on Equity
for Canadian and U.S. Gas and Electric Utilities
Volume V, May 25, 2017

INTRODUCTION

Concentric Energy Advisors, Inc. (Concentric) is pleased to publish the fifth edition of this newsletter. Each edition summarizes the latest information available on authorized ROEs and common equity ratios for over 40 Canadian gas and electric utilities. For comparison purposes, the newsletter also presents the average and median authorized ROEs and common equity ratios for U.S. gas and electric distributors, as reported by SNL Financial's Regulatory Research Associates.

ROE

Average and median allowed ROEs for both Canadian and U.S. utilities in 2017 remain little changed from their 2016 levels. The 2017 median ROE for gas distributors in Canada is 8.93% vs. 9.25% in the U.S. The 2017 median ROE for electric distribution and electric transmission is 8.50% in Canada and 9.60% in the U.S. Factoring into these averages were modest 20 basis point increases in the Alberta allowed ROEs, offset by the reduction in Ontario allowed ROEs as the Board's formula re-set with lower bond yields. Ontario, has a formula linked to both government bond yields and utility bond yields. The OEB's formula produces an 8.78% ROE for 2017, based on a long Canada bond yield input of 2.04%.

The sustained period of very low government bond yields has created challenges for both regulators and analysts as they grapple with the appropriate level of bond yields for cost of capital models. Where the Capital Asset Pricing Model (CAPM) is employed, it is recognized that central banks have depressed government bond yields, requiring some form of adjustment to produce reasonable results. The Discounted Cash Flow (DCF) model is linked to utility dividend yields, and is therefore not directly tied to government bond yields. But low bond yields have driven utility dividend yields lower, and when combined with strong stock valuations, the results of the DCF model are also impacted. In response, regulators and analysts are incorporating adjustments to traditional cost of capital models, or the ranges they produce, to reflect these market circumstances. For example, the British Columbia Utilities Commission, in its 2016 decision for FortisBC Energy, acknowledged that the current risk-free rate has been impacted by the accommodative monetary policy of global central banks, and that an adjustment was necessary to reflect the normalization in interest rate conditions expected in capital markets. In Alberta, the Alberta Utilities Commission recognized in the 2016 generic cost of capital decision that the CAPM results were being distorted by market conditions and therefore placed more weight than usual on the DCF model. The Régie in Québec had reached a similar conclusion in its 2013 Hydro Québec decision, recognizing that an adjustment was necessary to the risk-free rate used in the CAPM to reflect more sustainable long-term bond yields.

Additionally, our research has shown that the "equity risk premium" allowed by regulators over the government bond yield moves in an inverse relationship to interest rates. When interest rates are high, the risk premium is smaller, and vice versa. Significant changes in interest rates lead to corresponding changes in the equity risk premium. Regulators have responded in various ways to this relationship so as to moderate the impacts of volatile capital market conditions. For example, in Ontario, gradualism is implicit in the operation of the OEB's adjustment formula where changes in government and corporate bond yields result in a smaller change in the allowed ROE for regulated utilities. The OEB staff issued a report in January 2016 regarding the effectiveness of the ROE formula that was modified in 2009 to consider both changes in government and corporate bond yields. According to the OEB report, the revised formula has worked as intended since 2009, and has generally been well-received by utilities and stakeholders.

A notable trend over the past several years has been the closure of the gap that had developed between median allowed ROEs for Canadian and U.S. utilities. At its peak in 2007–08, the difference was 141 basis points for gas distributors, and 164 basis points for electric distributors. In 2017, the difference has narrowed to 32 and 110 basis points, respectively. ROEs for Canadian electric transmission companies are now equal to those awarded to Canadian electric distributors, and 110 basis points below those allowed U.S. electric distributors. All transmission companies but AltaLink and ATCO are provincially or municipally owned corporations.

CONCENTRIC ENERGY ADVISORS

Authorized Return on Equity
for Canadian and U.S. Gas and Electric Utilities
Volume V, May 24, 2017, p. 2

EQUITY RATIOS

The median authorized common equity ratio has declined slightly over the past few years in both Canada and the U.S. The gas distribution equity ratio is now 39.25% in Canada, vs. 51% in the U.S. The median electric distribution equity ratio is now 37% in Canada and 49.4% in the U.S. Electric transmission equity ratios have risen to 37% in Canada.

The prevailing differences between allowed equity ratios in Canada and the U.S. remain attributable to a few factors. Regulators in both countries rely on peer group analysis, which reinforces existing levels of allowed equity ratios. Regulators in Canada also look for material differences in risk or financial metrics before changing the allowed equity ratio, so they tend to remain relatively stable. While credit rating agencies notice the greater leverage of Canadian companies, and rank some of these utility companies as "Aggressive" in terms of financial risk, most companies have been able to maintain A or A- level credit ratings, so the regulatory response has been muted.

RECENT DECISIONS

Several important cases were decided in the second half of 2016 and first quarter of 2017. In British Columbia, the Commission maintained the allowed return of 8.75% and the deemed equity ratio of 38.5% for FortisBC Energy, Inc., the gas distributor which serves as the "benchmark" for other BC gas and electric utilities, and is used by the Yukon Utilities Board for similar purposes.

In Alberta, the Commission issued its decision in the generic cost of capital proceeding, establishing the approved ROE and capital structures for the Alberta utilities for 2016 and 2017. The generic ROE was set at 8.30% for 2016 and 8.50% for 2017 for regulated utilities in Alberta, and the common equity ratio was deemed at 37.0% for most Alberta transmission and distribution utilities, except AltaGas, which was granted a common equity ratio of 41.0%.

In Newfoundland, the Board maintained Newfoundland Power's deemed equity ratio of 45.0%, while reducing its authorized ROE to 8.50%. A decision was also issued in Newfoundland and Labrador Hydro's long-standing rate case, in which the government-owned utility was granted an allowed ROE of 8.50% and a deemed equity ratio of 25.2%.

The Yukon Utilities Board recently issued a decision re-instating an ROE premium of 25 basis points for ATCO Electric Yukon (AEY), which places the ROE at 9.0%. The Board determined that a risk premium was justified over the authorized ROE for the BC benchmark utility due to the small size of AEY.

The Ontario Energy Board recently conducted a hearing to consider the request of Ontario Power Generation (OPG) to increase its deemed equity ratio from 45% to 49% due to OPG's shift in generation mix from hydro to nuclear. A decision is expected from the OEB later this year.

BOND YIELDS

As shown in the chart on page 4, long-term government bond yields (considered the risk-free rate of return) in both Canada and the U.S. have increased by approximately 50 basis points since reaching a trough in July 2016. The accommodative policy of central banks combined with modest economic growth and a low inflationary environment have driven bond yields steadily lower in recent years. Regulators and analysts have responded with a combination of adjustments, equilibrium level bond yields, and alternative models to account for these anomalous market conditions. Consensus forecasts call for increasing bond yields over the next several years, but a complex mix of international and North American factors will determine the actual path of interest rates. In the interim, government bond yields remain a source of considerable uncertainty in financial markets and regulatory proceedings.

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Authorized Return on Equity for Canadian and U.S. Gas and Electric Utilities [1]

	Return on Common Equity (%)			Common Equity Ratio (%)		
	2015	2016	2017	2015	2016	2017
Canadian Gas Distributors [2]						
AltaGas Utilities Inc. [3]	8.30	8.30	8.50	42.00	41.00	41.00
ATCO Gas [3]	8.30	8.30	8.50	38.00	37.00	37.00
Centra Gas Manitoba Inc.	N/A	N/A	N/A	30.00	30.00	30.00
Enbridge Gas Distribution Inc. [4]	9.30	9.19	8.78	36.00	36.00	36.00
Enbridge Gas New Brunswick	10.90	10.90	10.90	45.00	45.00	45.00
FortisBC Energy Inc.	8.75	8.75	8.75	38.50	38.50	38.50
Gaz Métro Limited Partnership	8.90	8.90	8.90	38.50	38.50	38.50
Gazifère Inc.	9.10	9.10	9.10	40.00	40.00	40.00
Heritage Gas Limited	11.00	11.00	11.00	45.00	45.00	45.00
Pacific Northern Gas Ltd.	9.50	9.50	9.50	46.50	46.50	46.50
Pacific Northern Gas (N.E.) Ltd. (Fort St. John/Dawson Creek)	9.25	9.25	9.25	41.00	41.00	41.00
Pacific Northern Gas (N.E.) Ltd. (Tumbler Ridge)	9.50	9.50	9.50	46.50	46.50	46.50
SaskEnergy Inc.	8.75	8.30	8.30	37.00	37.00	37.00
Union Gas Limited [5]	8.93	8.93	8.93	36.00	36.00	36.00
Average	9.27	9.22	9.22	40.00	39.86	39.86
Median	9.10	9.10	8.93	39.25	39.25	39.25
U.S. Gas Distributors [6]						
Average of all Rate Cases Decided in the Year	9.60	9.49	9.60	49.93	49.69	51.57
Median of all Rate Cases Decided in the Year	9.68	9.50	9.25	50.40	50.00	51.00
Canadian Electric Distributors [2]						
ATCO Electric Ltd. [3]	8.30	8.30	8.50	38.00	37.00	37.00
ENMAX Power Corporation [3]	8.30	8.30	8.50	40.00	37.00	37.00
EPCOR Distribution Inc. [3]	8.30	8.30	8.50	40.00	37.00	37.00
FortisAlberta Inc. [3]	8.30	8.30	8.50	40.00	37.00	37.00
FortisBC Inc.	9.15	9.15	9.15	40.00	40.00	40.00
Hydro-Québec Distribution	8.20	8.20	8.20	35.00	35.00	35.00
Manitoba Hydro	N/A	N/A	N/A	25.00	25.00	25.00
Maritime Electric Company Limited	9.75	9.35	9.35	41.90	40.90	40.00
Newfoundland and Labrador Hydro	8.80	8.50	8.50	25.20	25.20	25.20
Newfoundland Power Inc.	8.80	8.50	8.50	45.00	45.00	45.00
Nova Scotia Power Inc.	9.00	9.00	9.00	37.50	37.50	37.50
Ontario's Electric Distributors [4]	9.30	9.19	8.78	40.00	40.00	40.00
Saskatchewan Power Corporation	8.50	8.50	8.50	40.00	40.00	40.00
Average	8.73	8.63	8.67	37.51	36.66	36.59
Median	8.65	8.50	8.50	40.00	37.00	37.00
U.S. Electric Distributors [6]						
Average of all Rate Cases Decided in the Year	9.60	9.60	9.68	49.26	48.60	47.42
Median of all Rate Cases Decided in the Year	9.53	9.60	9.60	50.00	49.55	49.40

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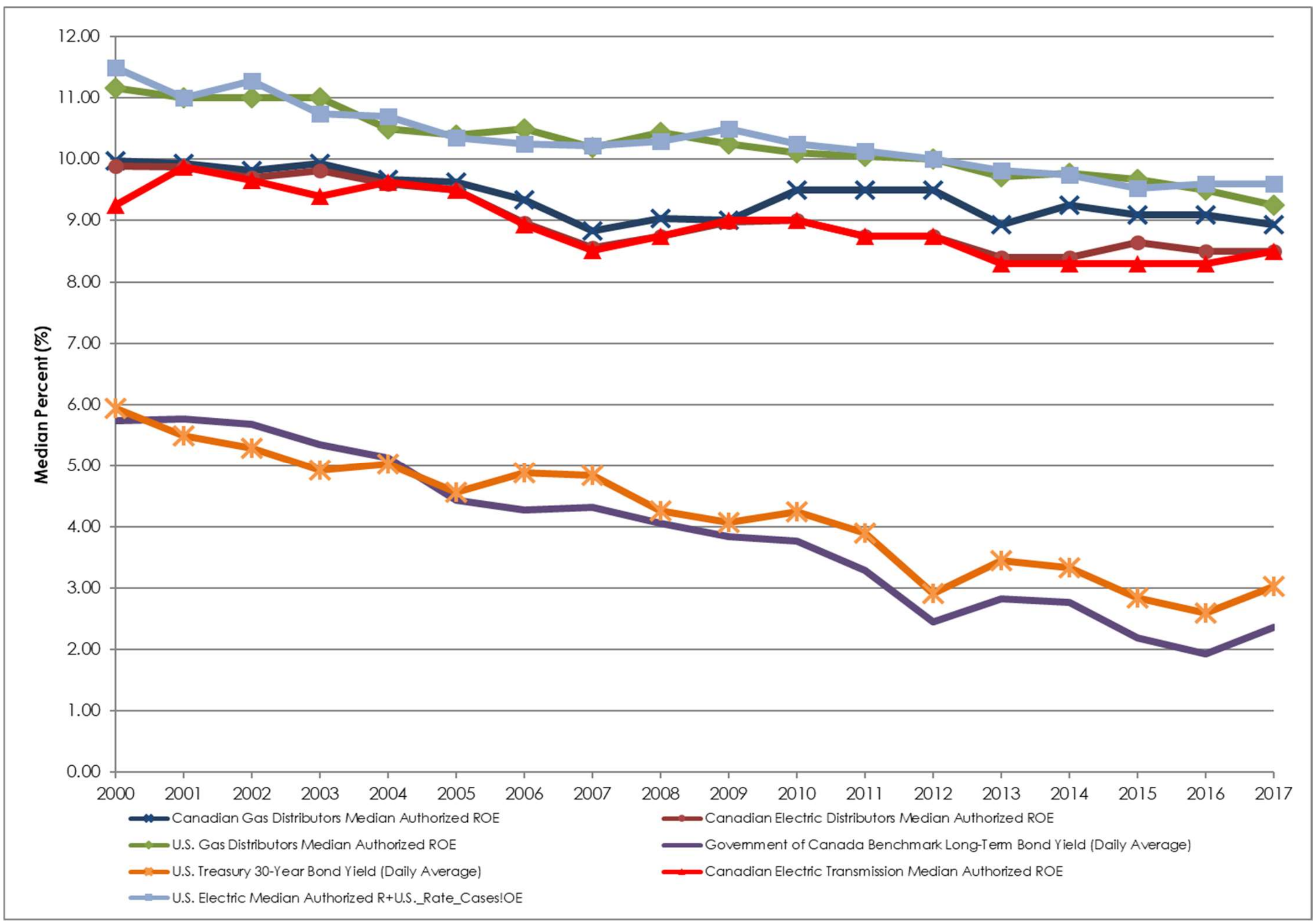
Authorized Return on Equity for Canadian and U.S. Gas and Electric Utilities	**Return on Common Equity (%)**			**Common Equity Ratio (%)**		
	2015	**2016**	**2017**	**2015**	**2016**	**2017**
Canadian Electric Transmission Companies [2]						
AltaLink Management Ltd. [3]	8.30	8.30	8.50	36.00	37.00	37.00
ATCO Electric Ltd. [3]	8.30	8.30	8.50	36.00	37.00	37.00
ENMAX Power Corporation [3]	8.30	8.30	8.50	36.00	37.00	37.00
EPCOR Transmission Inc. [3]	8.30	8.30	8.50	36.00	37.00	37.00
Hydro One Networks Inc. [4]	9.30	9.19	8.78	40.00	40.00	40.00
Hydro-Québec TransÉnergie	8.20	8.20	8.20	30.00	30.00	30.00
Average	8.45	8.43	8.50	35.67	36.33	36.33
Median	8.30	8.30	8.50	36.00	37.00	37.00

Economic Indicators (% Yields) [7]	**2015**	**2016**	**2017**
Government of Canada Benchmark Long-Term Bond Yield	2.19	1.92	2.36
U.S. Treasury 30-Year Bond Yield	2.84	2.60	3.04
Bloomberg Fair Value Canada A-rated Utility Bond Yield	3.82	3.68	3.82
Moody's A-rated Utility Bond Index (U.S.)	4.12	3.93	4.18



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NOTES

1. Data for an expanded group of Canadian gas transmission companies is contained in the Concentric Energy Advisors Return on Equity Database.
2. Allowed in rates for the corresponding year; where the year overlaps, the rate/ratio shown prevails for the majority of the year. Sources: Regulatory decisions and documents; annual information forms; annual reports.
3. The Alberta Utilities Commission's 2016 decision in the Generic Cost of Capital proceeding was effective for rate years 2016 and 2017. Returns on common equity and common equity ratios were adjusted for 2016. This also affects the category averages for 2016 as compared to those reported last year.
4. Beginning in 2014, the Ontario Energy Board updates cost of capital parameters for setting rates in cost of service applications only once per year.
5. Union's ROE per settlement agreement in its five-year incentive regulation plan for 2014–2018.
6. Source: SNL Financial LC's Regulatory Research Associates Division. Data for 2017 includes decisions through April 13, 2017.
7. Average daily yield. Source: Bloomberg Finance L.P. Data for 2017 through April 12, 2017.

* N/A indicates the data are not available. In recent years, the Manitoba Board has not established an authorized ROE for Manitoba Hydro, but has considered whether the company has sufficient income to meet certain interest coverage ratios and capital coverage ratios at its target debt/equity ratio. Similarly, Centra Gas Manitoba previously operated under an ROE adjustment mechanism tied to government bond yields. Centra Gas contended in its 2013/14 GRA filing that the formula was not producing reasonable returns. The Board directed Centra Gas to propose an update to the ROE that is reflective of an appropriate level to be used in the feasibility test.

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