EB-2020-0290

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Ontario Power Generation Inc. for an order or orders approving payment amounts for prescribed generating facilities commencing January 1, 2022.

COMPENDIUM OF THE SCHOOL ENERGY COALITION
(Motions Day)

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May 14, 2021
Our File: EB20200290

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

Attn: Christine Long, Registrar

Dear Ms. Long:

Re: EB-2020-0290 – Ontario Power Generation Inc. 2020-2026 – Motions Day

We are counsel to the School Energy Coalition ("SEC"). Pursuant to Procedural Order No. 2, below is a list of refused interrogatories, questions, and undertakings which SEC will address at the Motions Day, and the rationale for why the information is relevant and should be produced by Ontario Power Generation Inc. ("OPG").

1. ***SEC-8*** (L-A1-03-SEC-8)

This question seeks information on a claim in OPG's OEB Scorecard Management Discussion and Analysis that it has higher fuel costs for hydroelectric.[1] Since hydroelectric does not have fuel, this likely refers to the Gross Revenue Charge ("GRC"), but SEC was seeking to ensure that we were clear on the reference. This is tied to the issue of whether the Board accepts OPG's position that it cannot look at existing hydroelectric costs due to section 6(3)13 of O.Reg. 53/05.

2. ***SEC-13*** (L-A2-02-SEC-013)

SEC seeks this information to understand more completely whether hydroelectric costs have gone down materially since they were last established, and whether they are likely to continue to go down over the next five years. The information is relevant to two potential questions: a) Should the hydroelectric payment amounts be adjusted prior to December 31, 2021?, and b) Should the Board establish an asymmetrical Earning Sharing Mechanism ("ESM") account for hydroelectric for the period January 1, 2022 to December 31, 2026? Neither of these questions are precluded by O.Reg.53/05. SEC followed up in the Technical Conference (Day 3, p.2-4) and again was met with a refusal, even though segmented information is a regular feature of financial reporting.

3. ***SEC-46*** (L-C1-01-SEC-046)

As with SEC-13 above, SEC seeks this information to understand more completely whether hydroelectric costs have gone down materially since they were last established (for example due to

[1] Exhibit A1-3-2, Attachment 2, p.3

declining interest rates), and whether they are likely to continue to go down over the next five years. The information is relevant to two potential questions: a) Should the hydroelectric payment amounts be adjusted prior to December 31, 2021?, and b) Should the Board establish an asymmetrical ESM account for hydroelectric for the period January 1, 2022 to December 31, 2026? Neither of these questions are precluded by O.Reg.53/05. SEC followed up on this at the Technical Conference, Day 2, p.160-161, and it does appear clear that interest costs for hydroelectric are going down. Declining costs and flat payment amounts create a likelihood of increasing ROE.

4. *SEC-154* (L-H1-01-SEC-154)

OPG objects to providing information relevant to the Capital Refurbishment Variance Account ("CRVA") reference amount for hydroelectric. In this case, SEC seeks information on the forecast, so that we can compare that to the amounts already included in rates. This will allow the Board to determine if the proposed reference amount truly reflects the amounts included in existing rates that are available for new capital spending.

5. *OPG's 2018-2021 Business Plan* (Technical Conference Transcript, Day 1, May 3, 2021), p.117, Ln 1-4.

SEC seeks this information for several overlapping reasons. First, the information is relevant to understanding OPG's business planning for the period after the issuance of the Board's decision in EB-2016-0152. In that decision, the Board ordered reductions to the proposed 2017 to 2021 capital in-service additions.[2] OPG's evidence is that it incorporated those reductions into its first business plan after the issuance of the Board's decision.[3] Yet, it is refusing to provide the relevant evidence to demonstrate this. Second, OPG's 2017 to 2021 in-service additions are higher than the Board approved amounts.[4] It is seeking approval to add that variance to its 2022 opening rate base. The 2018-2021 Business Plan is relevant to understanding OPG's business planning and internal annual forecasts that led to the increase in capital additions compared to the Board approved levels. What did OPG manage its in-service additions to, the OEB approved levels or those in the Business Plan? if the latter, what were those amounts? Third, the evidence also indicates that OPG's nuclear benchmarking annual targets that were provided on the record in EB-2016-0152 subsequently changed because of the revised business plan.[5] SEC seeks to understand the drivers of the changes to those targets.

6. *Economic Protocols for PGS Pumping* (Technical Conference Transcript. Day 2, May 6, 2021) p.83.

Counsel for Environmental Defence asked a number of questions about the operational and economic rules for the Sir Adam Beck pumped storage facility. SEC is also interested in this question, because it is OPG's responsibility to minimize SBG, and optimizing pumped storage is one way to do it. SEC followed up in the same Technical Conference session (p.150-2), and obtained some information, but it is still incomplete. OPG should provide the economic protocols for the PGS, so that the Board can assess whether SBG is being minimized appropriately.

[2] *Decision and Order* (EB-2016-0152), December 28, 2017, p.18
[3] Technical Conference Transcript, Day 1, p.163-164; D2-01-SEC-49
[4] Exhibit D2-1-3, Table 4a-b
[5] Technical Conference Transcript, Day 1, p.168-169

7. *Hydroelectric Costs in 2021* (Technical Conference Transcript Day 2, May 6, 2021) p.167.

SEC sought information on whether the Applicant expects regulated hydroelectric costs in 2021 to be lower than prior years, but counsel refused to allow the witnesses to respond. If the current hydroelectric payment amounts are materially above cost, plus a reasonable return, they are prima facie no longer just and reasonable. This goes to the same two issues as SEC-13 and SEC-46, above.

Yours very truly,
Shepherd Rubenstein P.C.

Mark Rubenstein

cc: Ted Doherty, SEC (by email)
Applicant and intervenors (by email)

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

EB-2020-0290

Ontario Power Generation Inc.

Application for payment amounts for the period from January 1, 2022 to December 31, 2026

DECISION ON ISSUES LIST
May 20, 2021

This is a decision by the Ontario Energy Board (OEB) approving an issues list to define the structure and scope of the EB-2020-0290 proceeding.

Ontario Power Generation Inc. (OPG) filed an application dated December 31, 2020, with the OEB under section 78.1 of the *Ontario Energy Board Act, 1998.* OPG's application seeks approval for changes in payment amounts for the output of its nuclear generating facilities in each of the five years beginning January 1, 2022 and ending on December 31, 2026. OPG also requested approval to maintain, with no change, the base payment amount it charges for the output of its regulated hydroelectric generating facilities at the payment amount in effect December 31, 2021 for the period from January 1, 2022 to December 31, 2026.

Procedural Order No. 1, dated February 17, 2021, made provision for, among other matters, the filing of a proposed issues list. On May 13, 2021, OEB staff filed a letter (May 13 Letter) with the OEB indicating that parties had reached agreement on a partial proposed issues list for the proceeding. Issues for which no agreement was reached were separately identified and pertained to hydroelectric payment amounts, hydroelectric capital plans, other revenues, deferral and variance accounts, and small modular reactor (SMR)-related costs.

The OEB held an issues list hearing on May 18, 2021 to review the May 13 Letter. The issues list hearing provided parties[1] with the opportunity to make submissions on issues for which no agreement was reached.

[1] Parties in attendance included: OPG, OEB staff, Association of Major Power Consumers in Ontario (AMPCO), Consumers Council of Canada (CCC), Energy Probe Research Foundation (Energy Probe), Environmental Defence Canada Inc. (Environmental Defence), Ontario Association of Physical Plant Administrators (OAPPA), Ontario Sustainable Energy Coalition (OSEA), Quinte Manufacturers

Proposed Issues for which Agreement was Reached

Attached as Schedule A to the May 13 Letter was a list of the settled issues that parties proposed for this proceeding.

Findings

The OEB approves issues on the partial issues list, as drafted, that were provided in Schedule A to the May 13 Letter. The OEB finds that these issues are appropriate for inclusion in the approved issues list, as they identify relevant issues for the proceeding and are consistent with OPG's application and the OEB's jurisdiction.

Proposed Issues for which No Agreement was Reached

The OEB has considered all submissions on the issues for which no agreement was reached. The submissions of the parties are referred to, where required, below.

Hydroelectric Payment Amounts

The May 13 Letter indicated that parties proposed two new issues related to hydroelectric payment amounts be included in the issues list. The two issues are addressed below.

Proposed Issue 1a: Should the current hydroelectric payment amount be adjusted prior to December 31, 2021?

Ontario Regulation (O. Reg) 53/05 provides that the first payment amount order for OPG's hydroelectric facilities that is effective on or after January 1, 2022 must set the base hydroelectric payment amount at the same level as it was at on December 31, 2021, and the order must stay in effect until at least December 31, 2026. Several intervenors expressed a desire to be able to test evidence regarding OPG's current hydroelectric payment amount with a view to possibly changing the payment amount prior to December 31, 2021. SEC provided a submission and argued that the inclusion of this issue would allow the OEB to gather and test evidence as to whether OPG's current 2021 hydroelectric payment amount is just and reasonable, considering it would be "frozen" until December 31, 2026.

Association (QMA), School Energy Coalition (SEC), and Vulnerable Energy Consumers Coalition (VECC).

SEC's submission was supported by CCC, VECC, OSEA, QMA, Energy Probe, OAPPA, AMPCO, and Environmental Defence.

In its submission, SEC estimated that, based on the 2019 annual reporting and record-keeping requirement (RRR)-type filing, the 2019 return on equity (ROE) for OPG's hydroelectric business is 11.08% or 192 basis points above the OEB-approved ROE of 9.16% for OPG's regulated businesses (i.e., nuclear and hydroelectric combined). Based on OPG's financial statements, SEC also provided a "back-of-envelope" estimate for OPG's 2020 ROE for the hydroelectric business of 12.44% or 328 basis points above the OEB-approved OPG rate of 9.16% (which is above the 300 basis point threshold that triggers an OEB review under the existing framework). As such, SEC submitted that there is a possibility that the 2021 hydroelectric payment amount may not be just and reasonable and that parties should be allowed to examine this issue in the proceeding. SEC also requested that OPG provide its 2020 RRR-type filing by May 31, 2021, instead of July 31, 2021, to inform the proceeding of any possible hydroelectric-specific overearnings experienced in 2020.

OPG argued against the inclusion of this issue and the submission made by SEC. OPG highlighted that the hydroelectric payment amount formula was set in OPG's previous payment amounts application (2017-2021 Payment Amounts Proceeding),[2] with annual updates issued by the OEB – as recent as December 2020[3]. As such, inclusion of the issue in this proceeding, as stated by OPG, would be a "collateral attack" against the December 2020 hydroelectric payment amount order and the rate framework established in the 2017-2021 Payment Amounts Proceeding. OPG further stated that it does not have a hydroelectric ROE or nuclear ROE. Instead, there is only an ROE for the regulated business as a whole.

Findings

The OEB will not include Issue 1a in the approved issues list.

The OEB has a responsibility to ensure that payment amounts are just and reasonable under section 78.1 of the *Ontario Energy Board Act, 1998*. The OEB recently reviewed and approved OPG's 2021 payment amount for the hydroelectric business in December 2020. Moreover, prior to issuing that order for 2021 hydroelectric payment amount, the OEB commenced a "regulatory review" of OPG's 2021 payment amounts generally on November 9, 2020.[4] The OEB explained that, in response to OPG's significant

[2] EB-2016-0152 / Decision and Order / December 28, 2017.
[3] EB-2020-0210 / Decision and Payment Amounts Order / December 3, 2020.
[4] EB-2020-0248 / Notice of Proceeding and Accounting Order / November 9, 2020.

overearnings in 2019, it was ordering OPG to establish a variance account to record earnings achieved in 2021 that are more than 300 basis points over the OEB-approved ROE (the 2021 Overearnings Variance Account), with disposition if any to be determined after a hearing. Through this mechanism, OPG's 2021 payment amounts for both hydroelectric and nuclear are subject to change in the event of actual overearnings in 2021 (though not the "base" hydroelectric payment amount that will be frozen for five years).

SEC questioned whether the government, with its regulation, intended to "bake into rates" excess earning for hydroelectric generation for the next five years.[5] The OEB finds that to the extent that OPG's hydroelectric payment amounts result in excess earnings, there are other mechanisms that can be explored as part of the current proceeding to address any concerns related to potential overearnings within the proposed 2022 to 2026 period. For instance, there was some discussion at the issues list hearing of an earnings sharing mechanism for the entire regulated business (nuclear and hydroelectric), or an overearnings variance account like the one that is currently in place for 2021. OPG did not suggest that the exploration of such tools would be out of scope in this proceeding. The OEB wishes to make it clear, without intending to signal either support or skepticism of such mechanisms, that they are in scope. To that effect, the OEB has decided to add Issue 2.2 under Rate Framework.

New Issue 2.2: Is it appropriate to establish an earnings sharing mechanism or similar type of mechanism for the 2022 to 2026 period?

In addition to the concerns discussed above, adding a new issue to get at the question of whether the 2021 hydroelectric payment amount remains just and reasonable (in effect whether there should be a hydroelectric rebasing) is problematic at this stage of the proceeding; there are other mechanisms for addressing any potential overearnings that are more appropriately considered.

Proposed Issue 1b: Is the operation by OPG of the regulated hydroelectric facilities consistent with optimal use of the assets, minimization of Surplus Baseload Generation, and maximization of value for customers? Are any adjustments to the Hydroelectric Incentive Mechanism required to incent greater optimization of hydroelectric assets?

Environmental Defence provided a submission for the inclusion of this issue, which was supported by CCC, OSEA and SEC. As part of its submission, Environmental Defence referenced a previous OPG payment amounts decision that directed OPG to optimize the use of its Pump Generating Station to limit Surplus Baseload Generation (SBG)-

[5] Issues List Hearing Transcript / p. 19

related impacts on ratepayers.[6] Environmental Defence also noted that OPG filed an SBG study on the record of the current proceeding. Environmental Defence indicated that the OEB's previous decisions and orders provide justification for the inclusion of the issue in this proceeding.

VECC and Energy Probe both submitted that a review of OPG's SBG practices should be in scope for the proceeding, but argued that the issue appears to be covered as part of the already settled issues list. VECC submitted that it was not clear as to what is new in the proposed Issue 1b that is not addressed under Issue 13.2,[7] related to deferral and variance accounts (DVA) which had been agreed to by parties. Although the base hydroelectric payment amounts will be frozen, OPG seeks to dispose of certain hydroelectric DVAs during the test period. Energy Probe submitted that Issue 13.2 should, and does, address the matter outlined in the proposed Issue 1b.

OPG also submitted that the proposed issue has elements that could be subsumed in Issue 13.2, as it proposed to dispose of the balance recorded in the Hydroelectric Surplus Baseload Generation Variance Account (SBGVA) in this proceeding. OPG raised a concern that the wording of the proposed issue was too broad and would be used as a vehicle to explore SBG in general, which it believes is not relevant to the proceeding. OPG stated that SBG is a system-wide result and is driven by a number of integrated factors in the Independent Electricity System Operator (IESO)-controlled grid. As such, OPG's hydroelectric assets do not necessarily control SBG, but are expected to respond to SBG.

The second aspect of proposed Issue 1b related to OPG's Hydroelectric Incentive Mechanism (HIM). SEC and Environmental Defence noted that O. Reg 53/05 specifically allows for changes to the HIM during the period that the base hydroelectric payment amounts are frozen.

OPG argued that any adjustments to the HIM should await a future OPG application, which is expected to be filed once the details of the IESO's Market Renewal Program (and how it may impact OPG) are better known.

Findings

The OEB will not include Issue 1b in the approved issues list. The OEB finds that Issue 13.2 is sufficient to address OPG's proposed disposition of the 2018 and 2019 SBGVA

[6] EB-2010-0008 / Decision with Reasons / March 10, 2011 / p. 147.
[7] Issue 13.2 states: "Are the balances for recovery and the proposed disposition amounts in each of the deferral and variance accounts related to OPG's nuclear and regulated hydroelectric assets appropriate?"

balance of $208 million. Issue 13.2 as stated will enable parties to assess the prudence of the amounts recorded in the SBGVA in the context of the OEB's EB-2010-0008 decision.

The OEB accepts OPG's explanation that the IESO's Market Renewal Program may affect OPG's HIM. The OEB notes that O. Reg 53/05 does not restrict the OEB's ability to review the HIM during the hydroelectric payment amount freeze, and the EB-2018-0243 decision required OPG to file a SBG Study in the current proceeding. However, the OEB has decided to defer consideration of both the SBG Study[8] and HIM, to be concurrent with its consideration of OPG's forthcoming Market Renewal Program application.

The OEB agrees with intervenors that SBG and the HIM are important issues, yet the OEB expects it would be more efficient to address these issues concurrent with any future review of a Market Renewal Program-related application by OPG, to avoid any potential duplication.

Other Revenues

As outlined in the May 13 Letter, no change was proposed to the issues list language for Other Revenues (Issue 11). However, a request was made for a determination on whether the following issue is in scope for the proceeding.

Proposed Issue 2a: What is the appropriate ratemaking treatment of gains on sale of assets for which a portion of the costs are recovered through asset service fees?

OEB staff believed the matter to be subsumed in Issue 11.1 while OPG did not. Counsel to OPG also noted discussions it had with counsel to OEB staff about addressing the matter at the motions hearing, scheduled for May 21, 2021. Both OPG and OEB staff agreed that addressing the matter at the motions hearing was acceptable. No parties expressed opposition to this proposed approach.

Findings

The OEB will maintain Issue 11.1 regarding other revenues as proposed. The OEB will determine the scope of Issue 11.1 after considering submissions from the parties at the motions hearing, scheduled on May 21, 2021.

[8] To the extent that the SBG Study is relevant to OPG's proposed disposition of the balance recorded in the SBGVA, the SBG Study is in scope for the current proceeding.

Deferral and Variance Accounts

With respect to deferral and variance accounts, parties were unable to agree as to whether a new issue should be included in the issues list. The proposed issue is as follows.

Proposed Issue 3a: Is the capital plan for the hydroelectric facilities, including capital that will be recorded in the Capacity Refurbishment Variance Account (CRVA), appropriate?

SEC provided a submission on this issue, which was supported by Environmental Defence. SEC noted that the OEB normally reviews future capital plans of a utility, in certain rate applications, to gain context on what the utility will undertake in future years. SEC also stated that there may be a significant balance in the CRVA by 2026. As such, reviewing the capital plan for hydroelectric facilities will allow the OEB to comment on: (1) whether it is appropriate; and (2) how it relates to other issues, such as rate smoothing, which will push cost recovery into future years.

OPG argued that a capital plan is not required in relation to its CRVA proposals as OPG is not seeking recovery of the hydroelectric-related CRVA balances in the current application. OPG further stated that capital plans for the hydroelectric business have not previously been needed in OPG payment amounts proceedings (in the circumstance where OPG is not seeking to set hydroelectric payment amounts on a cost basis). In addition, OPG noted that capital plans will not inform the establishment of rates – recognizing that the base hydroelectric payment amount will be frozen over the rate term.

Findings

The OEB will not include this proposed issue in the approved issues list. To the extent that OPG's capital plan for its hydroelectric business includes capacity refurbishment, OPG is able to record any applicable variance in the CRVA.

The OEB acknowledges the concerns of parties regarding the potential for balances to accumulate within the CRVA during the 2022 to 2026 period. The OEB has confirmed that DVA balances are provided and monitored as part of OPG's annual RRR-type filings. To inform the OEB's monitoring of the CRVA balance, the OEB may direct OPG to include the hydroelectric capital plan as part of its RRR-type reporting for the test period.

<u>*Small Modular Reactors (SMRs)*</u>

OPG has booked costs from 2020 and 2021 relating to SMRs in its Nuclear Development Variance Account (NDVA), yet OPG is not seeking any disposition of this account in the current proceeding. There was no agreement amongst parties as to whether SMR-related costs are an issue within the scope of this proceeding. As such, in the May 13 Letter, parties requested an OEB determination on whether SMR-related matters are in scope (or whether language describing the financial risks that are applicable to OPG related to SMR costs should be included in the Decision on Issues List).

AMPCO, VECC, OAPPA, QMA and Energy Probe all expressed concern regarding the amount of SMR-related costs recorded in the NDVA, with limited regulatory oversight or review. Parties also expressed concern about the quantum of SMR-related capital and non-capital costs that could potentially be incurred during the test period.

OPG objected and clarified that it was accepting the risks relating to SMR-related costs and that there is no requirement in O. Reg 53/05 that requires any of the expenditures to be pre-approved prior to booking in the NDVA. OPG took the position that SMR-related costs are being recorded in accordance with the scope of the account. Further, OPG stated that the balances would be subject to both a prudence review, and a review of whether the costs belong in the account at all, when OPG seeks disposition of such costs.

Findings

The OEB finds that SMR-related costs are within scope and subsumed within Issue 13.1 regarding the nature and type of costs recorded in DVAs and Issue 14.1 regarding OPG's annual RRR-type filings.

The OEB agrees with AMPCO that OPG raised the topic of SMR-related costs in its pre-filed evidence. OPG indicated that $272 million was to be recorded in the NDVA for expenses in 2020 and 2021.

The NDVA is addressed in O. Reg 53/05 and the account was approved as part of the EB-2007-0905 decision. However, there appears to be disagreement among parties regarding the appropriate use of the NDVA to record SMR-related costs.

This issue is before the OEB in this proceeding. There are financial risks to OPG's shareholder and ratepayers associated with ambiguity regarding an existing DVA. The

OEB will consider the narrow issue of whether OPG's SMR-related costs are consistent with the purpose of the NDVA and thereby appropriate to be booked in the account.

THE ONTARIO ENERGY BOARD THEREFORE ORDERS THAT:

1. The approved issues list is attached to this Decision as Schedule A.

DATED at Toronto, **May 20, 2021**

ONTARIO ENERGY BOARD

Original Signed By

Christine E. Long
Registrar

SCHEDULE A

APPROVED ISSUES LIST

ONTARIO POWER GENERATION INC.

EB-2020-0290

MAY 20, 2021

ONTARIO POWER GENERATION INC.
2022-2026 PAYMENT AMOUNTS
EB-2020-0290
ISSUES LIST

1. GENERAL

1.1 Has OPG responded appropriately to all relevant OEB directions from previous proceedings?

1.2 How could OPG further improve its customer engagement process?

2. RATE FRAMEWORK

2.1 Is OPG's approach to incentive rate-setting for establishing the nuclear payment amounts appropriate?

2.2 Is it appropriate to establish an earnings sharing mechanism or similar type of mechanism for the 2022 to 2026 period?

3. NUCLEAR BENCHMARKING

3.1 Is the nuclear benchmarking methodology reasonable? Are the benchmarking results and targets flowing from OPG's nuclear benchmarking reasonable?

4. IMPACT OF COVID-19 PANDEMIC

4.1 Is OPG's proposed ratemaking treatment of the COVID-19 pandemic-related impacts appropriate?

5. RATE BASE

5.1 Are the amounts proposed for nuclear rate base appropriate?

6. CAPITAL STRUCTURE AND COST OF CAPITAL

6.1 Are OPG's proposed capital structure and rate of return on equity appropriate?

6.2 Are OPG's proposed costs for the long-term and short-term debt components of its capital structure appropriate?

7. CAPITAL PROJECTS

7.1 Do the costs associated with the nuclear projects that are subject to section 6(2)4 of O. Reg 53/05 and proposed for recovery meet the requirements of that section?

7.2 Are the proposed nuclear capital expenditures and/or financial commitments (excluding those for the Darlington Refurbishment Program) reasonable?

7.3 Are the proposed nuclear capital expenditures and/or financial commitments for the Darlington Refurbishment Program reasonable?

7.4 Are the proposed test period in-service additions for nuclear projects (excluding those for the Darlington Refurbishment Program) appropriate?

7.5 Are the proposed test period in-service additions for the Darlington Refurbishment Program appropriate?

7.6 Are the proposed test period in-service additions for the D2O Project reasonable?

8. PRODUCTION FORECASTS

8.1 Is the proposed nuclear production forecast appropriate?

9. COMPENSATION

9.1 Are the test period human resource related costs for the nuclear facilities (including wages, salaries, payments under contractual work arrangements, benefits, incentive payments, overtime, FTEs and pension and other post-employment benefit costs) appropriate?

10. OPERATING COSTS

10.1 Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

10.2 Is the forecast of nuclear fuel costs appropriate?

Corporate Costs

10.3 Are the corporate costs allocated to the nuclear business appropriate?

10.4 Are the centrally held costs allocated to the nuclear business appropriate?

10.5 Are the asset service fee amounts charged to the nuclear business appropriate?

Depreciation

10.6 Is the proposed test period nuclear depreciation expense appropriate?

Income and Property Taxes

10.7 Are the amounts proposed to be included in the test period nuclear revenue requirement for income and property taxes appropriate?

11. OTHER REVENUES

Nuclear

11.1 Are the forecasts of nuclear business non-energy revenues appropriate?

Bruce Generating Station

11.2 Are the test period costs related to the Bruce Generating Station, and costs and revenues related to the Bruce lease appropriate?

12. NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

12.1 Is the revenue requirement methodology for recovering nuclear liabilities in relation to nuclear waste management and decommissioning costs appropriate?

12.2 Is the revenue requirement impact of the nuclear liabilities appropriately determined?

13. DEFERRAL AND VARIANCE ACCOUNTS

13.1 Is the nature or type of costs recorded and the methodologies used to record costs in the deferral and variance accounts related to OPG's nuclear and regulated hydroelectric assets appropriate?

13.2 Are the balances for recovery and the proposed disposition amounts in each of the deferral and variance accounts related to OPG's nuclear and regulated hydroelectric assets appropriate?

13.3 Is the proposed continuation of deferral and variance accounts related to OPG's nuclear and regulated hydroelectric assets appropriate?

13.4 Are the deferral and variance accounts that OPG proposes to establish appropriate?

14. REPORTING AND RECORD KEEPING REQUIREMENTS

14.1 Are the proposed reporting and record keeping requirements, including performance scorecards proposed by OPG, appropriate?

15. RATE SMOOTHING

15.1 Is OPG's proposal for smoothing nuclear payment amounts consistent with O. Reg. 53/05 and appropriate?

16.1 IMPLEMENTATION

16.1 Are the effective dates for new payment amounts and riders appropriate?

5.4 (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under section 78.1 of the Act, differences between actual non-capital costs incurred and firm financial commitments made and the amount included in payments made under that section for planning and preparation for the development of proposed new nuclear generation facilities. O. Reg. 27/08, s. 1.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 27/08, s. 1.

Darlington refurbishment rate smoothing deferral account

5.5 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the commencement of the deferral period, the difference between,

(a) the revenue requirement amount approved by the Board that, but for subparagraph 12 i of subsection 6 (2) of this Regulation, would have been used in connection with determining the payments to be made under section 78.1 of the Act each year during the deferral period in respect of the nuclear facilities; and

(b) the portion of the revenue requirement amount referred to in clause (a) that is used in connection with determining the payments made under section 78.1 of the Act, after determining, under subparagraph 12 i of subsection 6 (2) of this Regulation, the amount of the revenue requirement to be deferred for that year in respect of the nuclear facilities. O. Reg. 353/15, s. 2.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account at a long-term debt rate reflecting Ontario Power Generation Inc.'s cost of long-term borrowing that is determined or approved by the Board from time to time, compounded annually. O. Reg. 353/15, s. 2.

Pickering closure costs deferral account

5.6 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records any employment-related costs and non-capital costs related to third party service providers incurred by Ontario Power Generation Inc. that arise from any Pickering closure activities, including,

(a) costs related to employee termination, layoff, reassignment or retraining; and

(b) costs related to the hiring of employees or the engagement of third party service providers to perform Pickering closure activities, and their remuneration. O. Reg. 622/20, s. 2.

(2) Subsection (1) applies whether the costs are incurred before or after a Pickering closure, but does not apply to,

(a) costs that are eligible for recovery by Ontario Power Generation Inc. under the Ontario Nuclear Funds Agreement; or

(b) for greater certainty, costs that have already been included in an order made by the Board under section 78.1 of the Act. O. Reg. 622/20, s. 2.

(3) Ontario Power Generation Inc. shall record Pickering closure costs in the deferral account as they are reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc., and shall record interest on the balance of the account as the Board may direct. O. Reg. 622/20, s. 2.

Rules governing determination of payment amounts by Board

6. (1) Subject to subsection (2), the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act. O. Reg. 53/05, s. 6 (1).

(2) The following rules apply to the making of an order by the Board that determines payment amounts for the purpose of section 78.1 of the Act:

1. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the variance account established under subsection 5 (1) over a period not to exceed three years, to the extent that the Board is satisfied that,

    i. the revenues recorded in the account were earned or foregone and the costs were prudently incurred, and

ii. the revenues and costs are accurately recorded in the account.

2. In setting payment amounts for the assets prescribed under section 2, the Board shall not adopt any methodologies, assumptions or calculations that are based upon the contracting for all or any portion of the output of those assets.
3. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5 (4). The Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 15 years.
4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs and firm financial commitments incurred in respect of the Darlington Refurbishment Project or incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,

   i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or

   ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

4.1 The Board shall ensure that Ontario Power Generation Inc. recovers the costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities, to the extent the Board is satisfied that,

   i. the costs were prudently incurred, and

   ii. the financial commitments were prudently made.

5. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., the Board shall accept the amounts for the following matters as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors of Ontario Power Generation Inc. before the effective date of that order:

   i. Ontario Power Generation Inc.'s assets and liabilities, other than the variance account referred to in subsection 5 (1), which shall be determined in accordance with paragraph 1.

   ii. Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations.

   iii. Ontario Power Generation Inc.'s costs with respect to the Bruce Nuclear Generating Stations.

6. Without limiting the generality of paragraph 5, that paragraph applies to values relating to,

   i. capital cost allowances,

   ii. the revenue requirement impact of accounting and tax policy decisions, and

   iii. capital and non-capital costs and firm financial commitments to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2.

7. The Board shall ensure that the balance recorded in the deferral account established under subsection 5.2 (1) is recovered on a straight line basis over a period not to exceed three years, to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded in the account, based on the following items, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc.,

i. return on rate base,

ii. depreciation expense,

iii. income and capital taxes, and

iv. fuel expense.

7.1 The Board shall ensure the balance recorded in the variance account established under subsection 5.4 (1) is recovered on a straight line basis over a period not to exceed three years, to the extent the Board is satisfied that,

i. the costs were prudently incurred, and

ii. the financial commitments were prudently made.

7.2 The Board shall ensure that the balance recorded in the deferral account established under subsection 5.6 (1) and related income tax effects are recovered on a straight line basis over a period not to exceed 10 years beginning on the day the last generating unit of the Pickering A Nuclear Generating Station and Pickering B Nuclear Generating Station permanently stops generating electricity, to the extent that the Board is satisfied that the costs were prudently incurred and are accurately recorded in the account.

8. The Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.

9. The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.

10. If Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations exceed the costs Ontario Power Generation Inc. incurs with respect to those Stations, the excess shall be applied to reduce the amount of the payments required under subsection 78.1 (1) of the Act with respect to output from the nuclear generation facilities referred to in paragraphs 3, 4 and 5 of section 2.

11. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc. that is effective on or after July 1, 2014, the following rules apply:

i. The order shall provide for the payment of amounts with respect to output that is generated at a generation facility referred to in paragraph 6 of section 2 during the period from July 1, 2014 to the day before the effective date of the order.

ii. The Board shall accept the values for the assets and liabilities of the generation facilities referred to in paragraph 6 of section 2 as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors before the making of that order. This includes values relating to the income tax effects of timing differences and the revenue requirement impact of accounting and tax policy decisions reflected in those financial statements.

12. For the purposes of section 78.1 of the Act, in setting payment amounts for the nuclear facilities during the deferral period,

i. the Board shall determine the portion of the Board-approved revenue requirement for the nuclear facilities for each year that is to be recorded in the deferral account established under subsection 5.5 (1), with a view to making more stable the year-over-year changes in the OPG weighted average payment amount over each calculation period,

ii. the Board shall determine the approved revenue requirements referred to in subsection 5.5 (1) and the amount of the approved revenue requirements to be deferred under subparagraph i on a five-year basis for the first 10 years of the deferral period and, thereafter, on such periodic basis as the Board determines,

iii. for greater certainty, the Board's determination of Ontario Power Generation Inc.'s approved revenue requirement for the nuclear facilities shall not be restricted by the yearly changes in payment amounts in subparagraph i,

iv. the Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5.5 (1), and the Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 10 years commencing at the end of the deferral period, and

v. the Board shall accept the need for the Darlington Refurbishment Project in light of the Plan of the Ministry of Energy known as the 2013 Long-Term Energy Plan and the related policy of the Minister endorsing the need for nuclear refurbishment.

13. In making its first order under section 78.1 of the Act that is effective on or after January 1, 2022 setting payment amounts for the hydroelectric facilities, the following rules apply:

i. The order shall provide for a base payment amount for the hydroelectric facilities that is equal to the base payment amount for the hydroelectric facilities on December 31, 2021, and that applies until the effective date of a subsequent order setting payment amounts for the hydroelectric facilities that comes into effect after Dec 31, 2026.

ii. Subparagraph i applies with respect to only 50 per cent of the output of the Chats Falls generation facility. O. Reg. 23/07, s. 4; O. Reg. 27/08, s. 2; O. Reg. 312/13, s. 4; O. Reg. 353/15, s. 3; O. Reg. 57/17, s. 2; O. Reg. 622/20, s. 3 (1).

(3) For greater certainty, the rule set out in paragraph 13 of subsection (2) does not affect any authority of the Board to approve,

(a) changes to the hydroelectric incentive mechanism applicable to Ontario Power Generation Inc.;

(b) the establishment of or changes to deferral or variance accounts relating to the hydroelectric facilities; or

(c) the recovery of any amounts relating to the hydroelectric facilities that are recorded by Ontario Power Generation Inc. in a deferral or variance account referred to in clause (b), or any related payment amount riders. O. Reg. 622/20, s. 3 (2).

7. Omitted (provides for coming into force of provisions of this Regulation). O. Reg. 53/05, s. 7.

SCHEDULE

1. Abitibi Canyon.
2. Alexander.
3. Aquasabon.
4. Arnprior.
5. Auburn.
6. Barrett Chute.
7. Big Chute.
8. Big Eddy.
9. Bingham Chute.
10. Calabogie.
11. Cameron Falls.
12. Caribou Falls.
13. Chats Falls.
14. Chenaux.
15. Coniston.

SEC Interrogatory #8

Interrogatory

Reference: A1-3-2, Attachment 2, p.3

Please describe the nature of the "higher fuel costs" attributable to hydroelectric generation, and the amount of that increase in 2019.

Response

See Ex. L-A1-03-Energy Probe-001, part b).

2020 OPG Scorecard Management Discussion and Analysis (“2020 Scorecard MD&A”)

Regulated Hydroelectric Facilities Performance Measures

OPG’s regulated hydroelectric fleet consists of 54 stations with a combined capacity of 6,420 MW. The objectives of OPG’s hydroelectric operations include operating and maintaining the generating facilities in a safe, reliable, efficient and cost-effective manner, while increasing the output from, and pursuing opportunities to increase, the fleet’s generating capacity. OPG aims to increase the hydroelectric facilities’ output by improving operational flexibility, enhancing reliability, optimizing outage planning and, subject to water conditions, increasing availability to meet electricity system demand.

Given the long-term nature of OPG’s hydroelectric fleet, OPG maintains and improves the performance of existing hydroelectric generating stations through multi-year capital and non-capital investments including replacements and upgrades of turbine runners, and refurbishment or replacement of existing generators, transformers and control systems. Where economical and practical, OPG also pursues opportunities to refurbish, expand or redevelop its existing hydroelectric stations. As necessary, OPG also plans for repair, rehabilitation, or replacement of aging civil hydroelectric structures.

During 2019, OPG’s hydroelectric operations experienced challenging conditions due to record high water levels and flows as a result of high snow pack and substantial rain across much of Ontario. OPG safely and effectively managed within these conditions. While several hydroelectric measures were lower than 2019 targets, generally performance measures show improved performance in 2019 compared to 2018. This includes Total Recordable Injury Frequency (“TRIF”), Environmental Performance Index (“EPI”), Availability, and OM&A Unit Energy Cost. Equivalent Forced Outage Rates (“EFOR”) increased in 2019, largely due to equipment failures associated with the aging hydroelectric fleet. Total Generating Cost per Net MWh (“TGC”) for the regulated hydroelectric facilities increased in 2019 due to investment in asset rehabilitation. Performance measures and 2019 program performance results are further detailed below.

Hydroelectric Safety

- **Total Recordable Injury Frequency (per 200k hours)**

TRIF is defined as the average number of fatalities, lost time injuries, medical treatment injuries and restricted work injuries per 200,000 hours worked.

The 2019 TRIF performance (1.32) exceeded the 2019 TRIF target (1.21) by 9%. While this metric exceeded target, the 2019 safety performance is nonetheless very strong, with better results than the preceding 3 years. Notably, the regulated hydroelectric facilities experienced only one lost time injury in 2019, no restricted work injuries, and no fatalities. This performance is the result of a focus on safety culture improvement, including observation and coaching practices, improved line of sight on safety incidents through modernization of reporting tools, and safety-related initiatives.

- **Environmental Performance Index (%)**

EPI is a weighted distribution of multiple measures, including the number of environmental spills, environmental regulatory infractions and social license initiatives with direct implication to the environment.

In 2019, the regulated hydroelectric facilities' EPI performance (150%) exceeded the 2019 target (100%) and 2018 performance (135%). This performance is due to the avoidance of any category A or B spills, no findings in multiple Environmental Compliance Assessment (ECA) inspections by the Ministry of the Environment, Conservation and Parks, and an ISO14001-certified Environmental Management System.

Hydroelectric Reliability

- **Availability Factor (%)**

The Availability Factor ("Availability") is a measure of the reliability of a generating unit, represented by the percentage of time the unit is capable of providing service considering planned maintenance outages, unplanned outages, and unit derates. The metric is reported on a Maximum Capacity Rating weighted average basis.

The 2019 Availability performance represents a slight increase (0.6%) from 2018 Availability performance. The 2019 Availability performance (86.6%) was less than the 2019 Availability target (88.0%), primarily due to an increase in unplanned outages largely attributable to equipment failures associated with an aging hydroelectric fleet that requires investment to improve reliability.

Availability performance was lower than target largely due to two forced outages at R.H. Saunders GS that each had a duration of approximately six months. The most recent mechanical and electrical overhauls of R.H. Saunders GS' turbines and generators were completed during the 1990s and early 2000s. OPG is planning to refurbish or replace aging turbine and generator equipment at R.H. Saunders through a sixteen year overhaul program. RG is also improving equipment monitoring by investing in the use of Advanced Pattern Recognition software models to predict failures and improve generating units' reliability.

- **Equivalent Forced Outage Rates (%)**

EFOR is an index of generating unit reliability measured by the ratio of time a generating unit is forced out-of-service, including equivalent forced deratings to the time the unit was operating or was forced out-of-service completely or partially. EFOR represents the percentage of time a unit is forced unavailable, as a function of intended service. Planned maintenance time and outages due to external causes are excluded from the denominator in the calculation of EFOR.

EFOR increased from 4.2% in 2018 to 6.4% in 2019, which did not meet the target of 1.80%. The primary driver of the 2019 EFOR performance was increased equipment failures due to an aging hydroelectric fleet that requires investment. Two major contributing factors were two forced outages at R.H. Saunders referred to in the discussion of 2019 Availability. OPG is implementing several initiatives to improve performance, including an asset management approach to maintain reliable operations, while balancing cost, risk and performance as well as investing in monitoring, diagnostics and equipment reliability tools for condition-based maintenance.

Hydroelectric Cost Effectiveness

- **OM&A Unit Energy Cost ($/MWh)**

OM&A Unit Energy Cost ("UEC") is a measure of financial productivity. It measures the Operations, Maintenance and Administrative (OM&A) costs per unit of energy produced (in MWh). OM&A UEC is calculated as the total OM&A expenditures, divided by annual generation.

The 2019 performance ($8.5/MWh) was better than the 2019 performance target ($8.7/MWh). This performance is a result of OPG's work to manage the upward pressure on OM&A costs due to the aging hydroelectric fleet, as well as increased output in 2019.

- **Regulated Facilities Total Generating Cost per Net MWh ($/MWh)**

TGC is defined as the total cost of operating the regulated hydroelectric facilities, which includes OM&A, fuel, sustaining capital, divided by generation. TGC is measured as a 3-year historical average to account for year-over-year fluctuations in capital expenditures.

This performance measure has increased by 3% from $23.4/MWh in 2018 to $24.1/MWh in 2019. The increase is attributed to capital investments to enhance dam safety, address end of life assets, and higher fuel costs, partially offset by increased production. Sustaining capital investments are required to support improving OPG's aging hydroelectric fleet's operation, reliability and safety.

Energy Probe Interrogatory #1

Interrogatory

Reference:
Exhibit A1, Tab 3, Schedule 2, Attachment 2, Page 2 - Hydro Performance Metrics

a) Please provide the historic 2015-2020 and 2021 targets for – Availability Factor, EFOR, OM&A Unit cost ($/MWh) and TGC ($/MWh).

b) Please discuss trends and actions to be taken to improve performance in the 2021-2026 outlook period.

Response

a) OPG's actual Availability Factor, EFOR, OM&A Unit Energy Cost ($/MWh) and TGC ($/MWh) for 2015-2020, and target for 2021, are provided in Chart 1.

Chart 1
Regulated Hydroelectric Performance Metrics

	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Target
Availability Factor [%]	91.2	89.0	88.0	86.0	86.6	88.2	86.2
EFOR [%]	1.8	2.4	3.3	4.2	6.4	5.6	2.3
OM&A Unit Energy Cost [$/MWh]	8.3	8.1	8.1	8.7	8.5	8.5	8.8
3-year Average Total Generating Cost per Net MWh [$/MWh]	21.5	22.3	22.9	23.4	24.1	25.3	27.7

b) OPG declines to respond on the basis of relevance. Ontario Regulation 53/05 section 6(2), 13, i, establishes the Hydroelectric payment amounts for the period covered by this application at the level that exists on December 31, 2021. As such, the information sought is not relevant to any issue before the OEB in this application.

SEC Interrogatory #13

Interrogatory

Reference: A2-2-1, Attachment 1, p.12

Please provide the forecast net income attributable to OPG regulated business, separated by hydroelectric and nuclear, for each between 2020 and 2026.

Response

OPG does not track or report net income separately for the regulated facilities.

[redacted]

[redacted]

[redacted]

Net Income

OPG forecasts generating over [redacted] per year of net income, on average, over the 2020-2026 period, reaching [redacted] by 2026. Over 2020 and 2021, this represents a [redacted] [redacted] in net income of approximately [redacted] compared to the 2019-2021 Business Plan.

[redacted]

As discussed below, [redacted] forecasted net income of [redacted] followed by a [redacted] reflects nuclear generation impacts arising from adjustments to the Darlington refurbishment and planned outage schedules in response to the COVID-19 pandemic. The net income profile over the 2022-2026 period reflects the impact of the assumed resetting of regulated rates, increase in rate base from the completion of the Darlington refurbishment, and [redacted].

The drivers of the [redacted] in net income to [redacted], compared to [redacted] in 2019, include:

- fewer refurbishment outage days at Darlington reflecting operation of all four units for a portion of the year upon Unit 2 returning to service, along with the deferred start of Unit 3 refurbishment later in the year, in response to the pandemic;
- fewer non-refurbishment planned outage days at Darlington reflecting deferral of the Unit 1 planned outage to 2021 in support of the revised refurbishment schedule in response to the pandemic;
- impact of refurbished Darlington Unit 2 entering rate base upon return to service in June 2020; and
- [redacted]

These factors are partially offset by the following:

- a larger planned outage program at Pickering in line with the station's planned outage schedule, which decreases nuclear production and increases OM&A expenses;
- lower capitalized interest related to Darlington refurbishment expenditures; and

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MR. MAUTI: I think at the very end of that response where it gets into how it is that we look at managing nuclear liabilities in terms of whether it's Bruce or prescribed, where I was trying to look to ways to ensure that we can discharge our obligations in the most efficient way possible, so that's the way we would go about approaching it, where liabilities, regardless of Bruce, versus the prescribed facilities, that would be our approach to try to manage those costs.

MR. SHEPHERD: So basically whatever you're doing to manage your own costs, whether it's liabilities or anything else, but let's say liabilities, which is the biggest cost, obviously, whatever you do to manage your own costs would also, to the extent that it relates to Bruce or to the extent that it carries over, you would do the same things to manage those costs?

MR. MAUTI: Yes, I would suggest that we don't do anything specific for Bruce versus prescribed when it comes to the costs, and again, as you mentioned, the majority of the costs related to the Bruce are tied to nuclear liabilities, and so there is a distinct set of options looking at the Bruce versus prescribed in that case.

MR. SHEPHERD: All right. Second -- my next question is A2-02-SEC-13, and this relates to net income for the regulated businesses.

MR. KOGAN: We can wait for that to be pulled up, but I do recall the response, Mr. Shepherd.

MR. SHEPHERD: All right. So you said you don't track a report net income separately for the regulated facilities, but your financial statements do segregate it between regulated hydroelectric and regulated nuclear, so I'm not sure I understand the answer.

MR. KOGAN: The financial statements segregate these amounts at the segmented level at the earnings before interest tax line, not at the net income.

MR. SHEPHERD: Okay. So can you give us -- can you answer the question on the basis of -- the only -- sorry, before interest and tax or before -- are we talking about EBITDA, or are we talking about earnings before EBIT?

MR. KOGAN: It's EBIT, so it's the latter, sir.

MR. SHEPHERD: Okay. So can you answer this question giving us EBIT? Do you have a forecast like that or can you produce one?

MR. KOGAN: The information is available within our business plan. This would be on an accounting basis, not on a regulated basis, and again, I'm sort of wondering from a hydroelectric perspective how this applies.

MR. SMITH: We're not going to provide it in relation to the regulated hydroelectric facilities.

MR. SHEPHERD: Is this in the business plan? This information? I didn't find it --

MR. KOGAN: This information is not in the business plan document, no, it is not.

MR. SHEPHERD: But you have it?

MR. KOGAN: Within the models that underlie our business plan we are able to estimate this information;

that's correct.

MR. SHEPHERD: But you're refusing to provide it?

MR. SMITH: We're refusing to provide it in relation to the regulated hydro facilities, yes.

MR. SHEPHERD: Awesome. Thank you. Now, I have a number -- I think basically all the rest of my questions, I'm not sure, but many of the rest of my questions relate to cost of capital, and these responses are mostly prepared by Concentric. I don't understand why Concentric was not -- why you don't have a Concentric witness at this technical conference. But what I'm going to do is I'm going to ask the questions, and if you can answer them you can answer them. If you can't answer them then you'll undertake them, I guess. Okay?

The first one is C1-01-SEC-20. And the thing I don't understand is, it's true, isn't it, that once you've completed the Unit 2 of the Darlington refurbishment plan, the -- or project, rather, your risk goes down because you know a lot more, right? Just operationally you're in a better position after you complete the first unit; is that right?

MR. KOGAN: I think I'll answer on behalf of the panel that certainly there would be an element of increased learning and opportunities to apply some of that learning to future units. I'm sure our Darlington refurbishment evidence speaks to those opportunities.

MR. SHEPHERD: Okay. Then my next question relates to SEC 21, which is the next one. And this -- we asked about

SEC Interrogatory #46

Interrogatory

Reference: C1-1-2, Table 12

Please confirm that the actual cost of interest on long term debt applicable to the regulated hydroelectric facilities for the period 2022-2026 is forecast to be approximately $130 million lower than the interest cost embedded in rates for that period.

Response

OPG declines to respond on the basis of relevance. O. Reg. 53/05 section 6(2), 13, i, establishes the Hydroelectric payment amounts for the period covered by this application at the level that exists on December 31, 2021. As such, the information sought is not relevant to any issue before the OEB in this application.

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interest rate environment; is that right?

MR. MAUTI: As part of our financing strategy, we always look at what we're carrying in terms of short-term commercial paper, looking at what's happening in the marketplace, and making those decisions. And yes, in part it is to capture the ability to lock in longer term paper at a lower rate.

Having said that, our short-term commercial paper is also at a very low rate. So it does become a trade-off and judgment call and assessment.

MR. SHEPHERD: And we see the lower interest cost in your evidence with respect to the interest costs associated with nuclear rate base, right? We're seeing it trend downward?

MR. MAUTI: Yes. If you look at C-1-1 evidence in terms of what the weighted average costs are for long and short-term debt, those rate forecasts reflect the environmental rate.

MR. SHEPHERD: They would also apply to hydroelectric, right? That is, you're not just refinancing the debt associated with nuclear; you finance on a corporate basis, so your cost of hydroelectric is also going down, right?

MR. MAUTI: Safe to say the financing costs for the corporation as a whole on a percentage basis are lower, yes.

MR. SHEPHERD: And that wouldn't be different for nuclear and hydroelectric, right? Because you finance globally, whatever percentage of rate base is hydroelectric is getting -- is attracting a lower cost of debt. Is that fair?

MR. KOGAN: I can answer that. For the issues that are corporate issues that are attributed across the entire organization, including nuclear and regular hydroelectric facilities, that would be correct.

MR. SHEPHERD: That wouldn't be correct for project financing, right? If you specifically finance a project, then whatever interest rate benefit or disbenefit, I suppose, that is not going to affect the rest of your borrowing, right, except in terms of credit rating stuff?

MR. KOGAN: One moment. That's correct. To the extent that there is financing that is related to specific projects or investments, our methodology for attributing the cost of debt would attribute those to the specific underlying project or investment.

MR. SHEPHERD: Thank you. Could you move to page 37, please? I'm looking at a footnote under the table. You say you don't have an approved hydroelectric rate base. What you have is the 7.49 billion that you had approved last time around.

But you do have an actual rate base, right? Forget whether you have an approved rate base. You actually record what assets you have and what your current rate base is, right, your actual?

MR. KOGAN: That's correct, and that forms the basis of some of the reporting that we do to the Board.

MR. SHEPHERD: Is that in the record somewhere, the

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assuming that the marketplace also values and sees that option going forward.

MR. SHEPHERD: Okay. Have you had any discussions with the rating agencies about the impact of this direction on either your ratings or -- and their risk perception or the cost of capital, the cost of debt?

MR. SHEPHERD: In discussion with the rating agencies, we are always looking for ways to position OPG in a way that obviously supports our investment rate credit rating, the fact that we are a clean energy generator and are starting to expand on our disclosures related to ESG, I think they would be supportive of that, but I'm not necessarily sure they're giving that much weight or credence to that in comparison to other risks they would be evaluating for us.

MR. SHEPHERD: And what I'm asking is, when you're talking to the rating agencies, are they reacting positively, negatively, neutral?

MR. MAUTI: The fact we are looking at these products and are positioning our financial disclosures this way is at least seen in a positive light as opposed to not.

MR. SHEPHERD: All right. I want to go to page 60, and this shows the regulated hydroelectric results, the segmented results from 2019 and 2020, and if I understand this correctly, your revenue was higher in 2020, but that's, I think, just a function of it goes up and down every year. But your OM&A went down and your depreciation went down. Am I right?

MR. KOGAN: The OM&A year-over-year did decrease, as shown here. The depreciation amortization in totality also decreased as shown here as well. Not to anticipate the question, but on the depreciation and amortization front in particular, the decrease is likely due to simply lower recoveries of deferral and variance accounts. So this is not fixed-asset depreciation, this is just amortization of regulatory balances and goes up and down without recovery through-riders.

MR. SHEPHERD: Are you able to break those two figures out, the 224 and the 214, between actual depreciation, like depreciation of PP&E, and amortization of regulatory assets? It's not in your financial disclosures here anywhere, but I'm sure you have those numbers.

MR. KOGAN: We certainly have the numbers, and it could be done. I'm just trying to understand what it's clarifying in terms of the context of this application.

MR. SHEPHERD: Well, so you're -- let me go on to the next question, then I'll circle back to it.

As Mr. Mauti has just said a few minutes ago, the interest costs associated with the hydroelectric rate base will also be going down, right?

MR. KOGAN: I don't want to speak for Mr. Mauti. I think what we said was that to the extent we were able to issue debt that brings down the overall corporate weighted average down that is attributable to the regulated business, then the actual deemed interest cost will decrease, and that's a correct statement.

MR. SHEPHERD: So -- and then the other thing is your taxes also are going down, because there are new tax rules in effect that allow you to accelerate some of your CCA.

MR. KOGAN: We record the impact of the enhanced CCA rules -- I think you're referring to the accelerated investment property -- in the appropriate variance accounts, either the CRVA or the income and the taxes variance account, and that includes the hydroelectric business, so therefore those impacts would not benefit, so to speak, our bottom-line tax expense.

MR. SHEPHERD: Oh, okay. Am I right that we can expect that 2021 numbers, in terms of earnings before interest and income taxes and earnings after interest, will also be relatively better than these ones, assuming similar generation?

MR. SMITH: Mr. Shepherd, can you help me with the relevance of this to this application?

MR. SHEPHERD: Yes. There is a disputed issue, and the issue is whether the Board continues to have jurisdiction to determine whether the hydroelectric payment amounts currently in place should remain in place for December 31st, 2021. And so I'm asking questions about the decline in costs at OPG for its hydroelectric business.

MR. SMITH: We're not going to answer those questions. I don't agree that -- I don't agree with the position that that is a relevant line of inquiry, having regard to the regulation.

MR. SHEPHERD: Okay. I'll take that as a refusal.

SEC Interrogatory #154

Interrogatory

Reference: H1-1-1, p.18

Please provide a table comparing the forecast $2 billion in hydroelectric capital additions annually to the proposed $153 million annual reference amount, and provide a forecast of the balance in the Hydroelectric CRVA as of December 31, 2026.

Response

OPG declines to provide the requested information on the basis of relevance. OPG is not seeking to recover actual or forecast hydroelectric balances in the CRVA in the application (see Ex. H1-1-1, p. 18).

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easy where the actuals are, but I -- the problem is I don't know the answer to your first question for all these metrics, so you may be right, but I would like to see that, I guess, that for 2017, '18, '19, and '20 the same dashboard, the sort of year-end dashboard.

MR. KEIZER: Assuming that it can be done. I mean --

MR. RUBENSTEIN: Assuming they exist.

MR. KEIZER: Assuming that they exist. Is that something we're able to do?

MR. SURDU: Yeah, we will try to take that on, Mr. Keizer, to provide information on actual amounts, on actual historical amounts.

MR. RUBENSTEIN: But I'm assuming there actually is a year end -- I assume at the end of the year of 2020 you have a version of this that someone looks at, the end of 2020. It's an actual forecast. You'll have the 2020 actuals, but there's -- like, this document exists at the end of the year?

MR. SURDU: A reporting similar to this should exist in the historical years. I can't confirm at this point that it will look exactly the same, Mr. Rubenstein.

MR. RUBENSTEIN: Okay. Well, I'm looking for that. I'm not looking for you to necessarily create something new that doesn't exist with new numbers and stuff like that and new targets. I'm looking for what actually exists for those years.

MR. SURDU: Understood.

MR. RUBENSTEIN: Okay. Can I ask you now -- if I can ask you to pull up D2-SEC-49. And the IR essentially asks you, you know, after the Board made certain disallowances in the last -- in its decision in the last proceeding, how did you modify your capital plan, explain the steps, and you provide a response. And at the end, what you say on line 38 is: OPG's specific capital expenditures and targets are effected in OPG's business plans developed over the 2018 to 2022 period.

Do I take it that what ended up happening is the Board gave you the decision in the 0152 case, and the revised capital targets are incorporated into a new business plan that's created to cover the 2018 to 2020 period. Do I have that right?

MR. ICYK: Yes, we do an annual business planning process, a multi-year business plan. When we got the OEB decision in December of 2017, at the next business planning iteration we would have incorporated the information from the OEB's decision. And the decision specifically stated, as noted on line 17, that the disallowances related to capital in-service. So we integrated that into our planning along with the other factors we talk about here, to arrive at that updated capital amounts for business plan and subsequent plan up until the time that we have the current business plan which underpins this rate application.

MR. RUBENSTEIN: What would be the business plan we're talking about here that you would have revised?

The decision is released 2017, and then is it the 2018 business plan, or 2019?

MR. ICYK: I would have to confirm to make sure I have the timing right. But it would have been the plan we developed in 118, which I believe would have been the '19 to '21 business plan.

MR. RUBENSTEIN: I haven't seen a 2019 to 2021 business plan. Can you provide and file that?

MR. ICYK: So I'll let Mr. Keizer talk; it looks like he wants to respond. Mr. Keizer, I think it's on mute.

MR. KEIZER: You want to see why, because it's relevant to the forecast period?

MR. RUBENSTEIN: As you're aware, the in-service additions over the last period were higher than what was approved, which you're seeking to close to rate base in the 2022 period, so obviously understanding how you incorporated and considered the Board's decision and its disallowance and what came out of that is obviously important.

MR. KEIZER: Wouldn't the most relevant evidence be what you have now, which is the actual projects and in-service additions that you're actually seeking relative to the Board approved?

MR. RUBENSTEIN: Understanding what your internal targets were, what your internal expectations and process goes to the prudence of whatever that [audio dropout] and the in-service additions ultimately were and the expenditures were.

MR. KEIZER: I'm not sure the purpose of going back and evaluating past business plans are, given the fact that what's the basis of -- what's in rate base is actually known as opposed to a projected view of the world at that time.

What the business plan reflects was what we're actually doing is saying we spent this, and it's based on reasonable and prudent expenditures, which are known and actual relative to Board-approved and projects done. I'm not the sure what the purpose of going back and evaluating business plans are.

MR. RUBENSTEIN: I think it's entirely relevant to understand after the decision what ultimately happened, understanding what did you take into account to be your actual forecasts at that time for what you thought you should do. Obviously, what flows out of it is what you did.

MR. KEIZER: What difference does it make?

MR. RUBENSTEIN: Understanding the decision-making process over the period to ultimately spend more than the Board approved.

MR. KEIZER: You indicated earlier that circumstances can change, things can get reprioritized. All those things can happen, so going back and evaluating it relevant to business planning, I don't see the relevance of it.

MR. RUBENSTEIN: I think it's entirely relevant. You're just taking this as a refusal?

MR. KEIZER: Yes.

MR. RUBENSTEIN: Okay. Just so I'm clear on what you're refusing here, we're talking about the 2019 to 2021 business plan. That was the first one that incorporated the changes that resulted from the Board's decision. Because you talk about --

MR. KEIZER: Mr. Icyk?

MR. ICYK: Yes, that's my recollection. I would ask Ms. Kerr to add if I said anything incorrect, but I believe that was the right timing.

MS. KERR: Yes, I would want to go back and clarify and confirm prior to committing to that.

MR. RUBENSTEIN: Okay. How about you provide an undertaking to tell me what was the business plan. I take it Mr. Keizer -- maybe the best way is over a break we do this. I want to make sure we know and it's on the record what the document that is being refused is. I think that would be helpful for any future process.

So I'm in Mr. Keizer's hands if it's a best we sort of -- what do you think is the best way to do this?

MR. KEIZER: I think the best way do it is -- I don't think we should -- unless you want to pursue further question on it, but I think the refusal is on the record. I think what we can do is -- what you were asking about is what is -- you want production of the business plan that reflects the implications of the Board decision issued in December of 2017, and whether that is one that relates to the 2018-2019 year or the 2019-2021 year, what's the basis of that business plan, and we can take it from that point. We can clarify -- to the extent that you are going to take the objection further, to clarify the dates in advance of that and we may be able to give you insight into that. I don't know if anyone can check from Regulatory Affairs before today is done, but we certainly can tell you before Thursday.

MR. RUBENSTEIN: Let me ask the -- because the transcript -- I'll ask the question and, Mr. Keizer, you can object.

Can OPG please provide the first business plan that came out that would have occurred after the Board's decision in EB 2016-0152?

MR. KEIZER: We will object to that question.

MR. RUBENSTEIN: Thank you very much. The next area I want to turn to is about nuclear benchmarking. Can we first pull up Staff 196, F2-01-Staff-196. If you can scroll down -- sorry, let's go to page 3.

In this interrogatory, you were asked to provide essentially the targets against the actuals for those years, do you see that? That's what was provided?

MR. ICYK: Yes, I see that.

MR. RUBENSTEIN: On page 4 -- sorry, the next page is with respect to Darlington. Now, when I went back and looked, compared those targets versus the targets you provided on the record in 0152 -- and just for the reference, that would be N 0152 at Exhibit F2-1-1, page 15 in chart 4.

For 2016 they are the same. But for 2017 and 2018 for a number of the metrics -- and here, just to be clear, I'm focusing on the top three -- the first three reliability metrics and the value for money metrics, the one I looked at -- they're different. Sometimes they're higher, sometimes they're lower. I'm just trying to understand why that would be the case.

MR. ICYK: So I just want to make sure I understand the question. So you're asking why are some of the numbers different here for 2017 onwards compared to what you saw filed in EB-2016?

MR. RUBENSTEIN: In EB-2016-0152 you provided three years of targets, 2016, '17, and '18, and for the set of metrics that I just talked about, the first three under reliability and all the value for money, in 2017 and 2018 for both Pickering and Darlington they differ. Some are higher, some are lower, and I'm trying to understand why that would be the case.

MR. ICYK: I think I would have to, you know, dig into the specifics and figure out why any particular thing would be different, but the thing that comes to mind related to 2018 is it's related to that kind of previous discussion we just had, which is, you know, at updated business plans we lock in targets going forward, and then we -- those would be reflected, so it's possible that they would -- you know, future years would be updated.

MR. RUBENSTEIN: Okay. So I take it then what your answer is, the targets that you put on in -- that you provided in your evidence in the last case, ultimately you do update those targets, and this reflects -- the interrogatory Staff 196 reflects the actual targets for those years?

MR. ICYK: It would reflect, like, the latest and greatest targets before the year starts.

MR. RUBENSTEIN: So for example -- so you --

MR. ICYK: And then I -- sorry, go ahead.

MR. RUBENSTEIN: No, no, you finish your --

MR. ICYK: I was going to say, as opposed to, you know, the business plan that underpinned EB-2016 and looked at things, you know, that locked in over the period. What's shown here is updated amounts.

MR. RUBENSTEIN: And so in the evidence you have 2021 through 2026 targets. Do you expect those will ultimately change over the next six years?

MR. ICYK: Well, as I mentioned, we do a business planning process on an ongoing basis, so, like, I wouldn't expect necessarily things to stay static. But these are our best estimates right now, our best forecasts based on rigorous planning that we have, because we're sitting here a snapshot in time, you know, point in time. So this is kind of the basis of how we're, you know, underpinning what we've provided in the rate application as using the best and most recent business plan.

MR. RUBENSTEIN: Can I ask you to turn to page 5 of this interrogatory? And so you provide here that annual targets for 2021 through 2026 for Darlington -- or, sorry, for Pickering on page 5 and then page 6 Darlington, correct?

MR. RUBENSTEIN: Yes, it is.

UNDERTAKING NO. JT1.25: TO COMPLETE EXHIBIT NO. KT1.2

MR. RUBENSTEIN: Give me a second to check my notes to see if I'm missing any questions here.

MR. SURDU: I would like to clarify the undertaking, Mr. Rubenstein.

MR. RUBENSTEIN: Sure.

MR. SURDU: You said the undertaking is to fill in the table we see on the screen?

MR. RUBENSTEIN: Yes.

MR. SURDU: Thank you.

MR. RUBENSTEIN: Just to be clear, it's with information at the time of the last proceeding, which presumably should have been on the record in the last proceeding. But maybe I'm missing the versions of these tables from the last proceeding.

MR. KEIZER: What was in evidence in the last proceeding is what fills in these blanks?

MR. RUBENSTEIN: The problem is that as I understand it, these are projects -- they're listed in your current D2-1-3 tables today that were from the last proceeding, but there's lots of other projects, this is a small sample, that we can not match up to the last proceeding.

MS. KERR: If this is an appropriate time, I want to provide a clarification to Mr. Rubenstein regarding the OEB order from the 2016 to the 2017 through 2021 IR period. The disallowances from that OEB rate application are incorporated in our 2018 through 2021 business plan.

MR. RUBENSTEIN: Okay. Can I have the -- can you provide the 2018 to 2021 business plan?

MR. KEIZER: This goes back to the previous refusal, so it's refused on the same basis.

MR. RUBENSTEIN: All right. Thank you very much. Panel, those are my questions. Thank you very much.

MR. MILLAR: Thank you very much, Mark. We still have a few minutes left in the day and I want to squeeze out every question I can. I think OEB Staff is up next. Lawrie, are you there? Can you give us 10 or 15 minutes?

EXAMINATION BY MR. GLUCK:

MR. GLUCK: I can do that. Good afternoon, panel. This is Lawrie Gluck on behalf of OEB Staff. I would like to follow up on a question Mr. Rubenstein just asked you. Can you advise whether the total generating cost metric uses a three year rolling average of capex or in-service additions?

MR. ICYK: Sorry, can you repeat the question?

MR. GLUCK: Can you advise whether the total generating cost metric in your benchmarking uses a three year rolling average on a capital expenditure basis, or is it on an in-service addition basis?

MR. ICYK: If we were looking at the benchmarking results and looking at a three year average historical, it would be the three years and it would be capital expenditures. If we were looking at forecast basis it would be one year forecast, and again it would be on a capital expenditure basis, so not an in-service basis in

SEC Interrogatory #49

Interrogatory

Reference: D2-1

After the Board made certain disallowances to the proposed 2017-2021 nuclear capital budget in its Decision and Order in EB-2016-0152, please explain how OPG modified its capital plan to account for the revised amounts approved by the Board. In your response, please not only explain the specific modifications made, but also the process taken to come to the changes.

Response

In its EB-2016-0152 Decision and Order, the OEB made disallowances to OPG's forecasted capital in-service amounts and did not comment in respect of OPG's planned capital expenditures over the 2017-2021 period.

When establishing capital expenditures targets for 2018 to 2021 during its annual business planning process, OPG considered a number of factors including the OEB's disallowances to capital in-service amounts. Other factors, which are typically considered as part of the annual business planning process, include reviewing regulatory requirements, investments needed to support equipment reliability and the associated capital expenditures necessary to execute multi-year projects that address these needs and requirements.

Capital expenditure plans over the 2018 to 2021 period also needed to consider continued investment to prepare for Darlington 'second life' operations. While the capital spending for Darlington operations is separate and distinct from capital spending on refurbishment, once the decision to refurbish Darlington to extend its life was approved, OPG began an extensive program to replace obsolete and/or life-expired plant equipment resulting in higher project related investments at Darlington (Ex. D2-1-2, pp. 3-4). Investing in life cycle management and other sustaining infrastructure investments at Darlington will help to position the station towards the long-term goal of returning to top-quartile TGC post refurbishment (Ex. F2-1-1, p. 2).

OPG's specific capital expenditure targets are reflected in OPG's business plans developed over the 2018-2020 period.

Table 4a
Comparison of In-Service Capital Additions - Nuclear Operations ($M)

Line No.	Business Unit	2016 Budget	(c)-(a) Change	2016 Actual	(g)-(c) Change	2017 OEB Approved[1]	(g)-(e) Change	2017 Actual	(k)-(g) Change	2018 OEB Approved[1]	(k)-(i) Change	2018 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Darlington NGS**	325.9	(105.6)	220.3	(16.3)	226.1	(22.1)	204.1	81.8	216.4	69.5	285.8
2	**Pickering NGS**	146.0	(98.0)	47.9	132.4	172.8	7.5	180.3	(113.9)	47.5	18.9	66.4
3	**Operations and Project Support[2]**	36.0	(34.2)	1.8	40.8	49.2	(6.6)	42.6	(26.2)	45.9	(29.5)	16.4
4	**Subtotal**	507.9	(237.8)	270.1	156.9	448.2	(21.2)	427.0	(58.4)	309.8	58.8	368.6
5	**Supplemental In-Service Forecast[3]**	(41.8)	41.8	0.0	0.0	(1.6)	1.6	0.0	0.0	24.9	(24.9)	0.0
6	**Total Portfolio In-Service Forecast**	466.0	(195.9)	270.1	156.9	446.6	(19.6)	427.0	(58.4)	334.7	33.9	368.6
7	**Darlington New Fuel**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	**Darlington Water Treatment Plant Lease**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	**Darlington Spacer Retrieval [4]**	0.0	0.0	0.0	5.8	6.4	(0.6)	5.8	(5.8)	0.0	0.0	0.0
10	**Pickering Extended Operations**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Minor Fixed Assets**	31.0	(14.7)	16.3	15.4	26.0	5.6	31.6	(9.9)	20.0	1.7	21.7
12	**In-Service Capital Additions before Disallowance**	497.0	(210.7)	286.4	178.0	479.0	(14.6)	464.4	(74.1)	354.7	35.6	390.3
13	**OEB Disallowance**					(47.9)				(35.5)		
14	**Total In-Service Capital Additions**	497.0	(210.7)	286.4	178.0	431.1	33.3	464.4	(74.1)	319.2	71.1	390.3

Line No.	Business Unit	2018 Actual	(e)-(a) Change	2019 OEB Approved[1]	(e)-(c) Change	2019 Actual	(i)-(e) Change	2020 OEB Approved[1]	(i)-(g) Change	2020 Budget	(k)-(g) Change	2021 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
15	**Darlington NGS**	285.8	(25.3)	295.7	(35.2)	260.5	(84.4)	101.3	74.9	176.1	63.4	239.5
16	**Pickering NGS**	66.4	(29.6)	9.7	27.0	36.8	(1.8)	29.7	5.2	34.9	(14.1)	20.9
17	**Operations and Project Support[2]**	16.4	(11.9)	44.3	(39.8)	4.5	16.6	0.0	21.1	21.1	44.3	65.4
18	**Subtotal**	368.6	(66.8)	349.8	(48.0)	301.8	(69.6)	131.0	101.1	232.1	93.6	325.8
19	**Supplemental In-Service Forecast[3]**	0.0	0.0	16.6	(16.6)	0.0	(20.4)	78.8	(99.2)	(20.4)	(2.7)	(23.1)
20	**Total Portfolio In-Service Forecast**	368.6	(66.8)	366.3	(64.5)	301.8	(90.0)	209.8	1.9	211.7	90.9	302.7
21	**Darlington New Fuel**	0.0	0.0	0.0	0.0	0.0	17.1	15.3	1.7	17.1	(17.1)	0.0
22	**Darlington Water Treatment Plant Lease**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	**Darlington Spacer Retrieval[4]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	**Pickering Extended Operations**	0.0	0.8	0.0	0.8	0.8	30.7	0.0	31.5	31.5	(26.4)	5.1
25	**Minor Fixed Assets**	21.7	1.8	19.1	4.5	23.5	(1.7)	19.5	2.4	21.9	2.2	24.1
26	**Total In-Service Capital Additions**	390.3	(64.2)	385.4	(59.3)	326.1	(43.9)	244.7	37.6	282.2	49.6	331.8
27	**OEB Disallowance**			(38.5)				(24.5)				
28	**Total In-Service Capital Additions**	390.3	(64.2)	346.9	(20.8)	326.107	(43.9)	220.2	62.0	282.2	49.6	331.8

Notes:

1 In-service additions per EB-2016-0152, Ex. J21.1, Attachment 2, Table 2. Amounts in this schedule do not reflect OEB-ordered reductions for: Auxiliary Heating System in-service amount (EB-2016-0152 Decision and Order, p. 21); Operations Support Building in-service amount (EB-2016-0152 Decision and Order, p. 22). These reductions are reflected in total nuclear rate base amounts in Ex. B3-2-1, Table 1. The 2017-2020 sub-components within the total portfolio in service forecast has also been adjusted for reclassification of projects from Darlington to Operations and Projects Support with no change to total amount.

2 Includes Engineering, Inspection and Reactor Innovation, and Security & Emergency Services.

3 Supplemental forecast to reconcile BCS in-service estimates to final business plan (see Ex. D2-1-3, Section 4.0).

4 Project #82949 DN X-750 Spacer Retrieval CMFA. OEB Approved amounts for Darlington Spacer Retreival per EB-2016-0152, Schedule 1, Staff-024, which were reflected in EB-2016-0152 Ex. J21.1, Attachment 2, Table 1.

Table 4b

Comparison of In-Service Capital Additions - Nuclear Operations ($M)

Line No.	Business Unit	2021 OEB Approved[1]	(c)-(a) Change	2021 Budget	(e)-(c) Change	2022 Plan	(e)-(c) Change	2023 Plan	(g)-(e) Change	2024 Plan	(i)-(g) Change	2025 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Darlington NGS**	62.1	177.5	239.5	170.2	409.7	(92.2)	317.6	(26.0)	291.6	82.7	374.3
2	**Pickering NGS**	0.0	20.9	20.9	(20.9)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	**Operations and Project Support[2]**	0.0	65.4	65.4	(52.0)	13.4	80.4	93.8	(93.8)	0.0	29.5	29.5
4	**Subtotal**	62.1	263.7	325.8	97.4	423.1	(11.8)	411.3	(119.7)	291.6	112.3	403.9
5	**Supplemental In-Service Forecast[3]**	100.2	(123.4)	(23.1)	14.6	(8.5)	37.7	29.2	(16.1)	13.1	24.8	37.9
6	**Total Portfolio In-Service Forecast**	162.3	140.4	302.7	112.0	414.7	25.9	440.5	(135.8)	304.7	137.1	441.8
7	**Darlington New Fuel**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.5	16.5	0.4	16.9
8	**Darlington Water Treatment Plant Lease**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	138.6	138.6	(138.6)	0.0
9	**Darlington Spacer Retrieval[4]**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10	**Pickering Extended Operations**	0.0	5.1	5.1	(5.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11	**Minor Fixed Assets**	19.3	4.7	24.1	(4.4)	19.6	1.4	21.0	8.2	29.2	(10.6)	18.7
12	**Total In-Service Capital Additions**	181.6	150.2	331.8	102.5	434.3	27.3	461.6	27.4	489.0	(11.7)	477.3
13	**OEB Disallowance**	(18.2)										
14	**Total In-Service Capital Additions**	163.5	168.3	331.8	102.5	434.3	27.3	461.6	27.4	489.0	(11.7)	477.3

Line No.	Business Unit	2025 Plan	(c)-(a) Change	2026 Plan
		(a)	(b)	(c)
15	**Darlington NGS**	374.3	(205.4)	168.9
16	**Pickering NGS**	0.0	0.0	0.0
17	**Operations and Project Support[2]**	29.5	(29.5)	0.0
18	**Subtotal**	403.9	(234.9)	168.9
19	**Supplemental In-Service Forecast[3]**	37.9	112.0	149.9
20	**Total Portfolio In-Service Forecast**	441.8	(123.0)	318.8
21	**Darlington New Fuel**	16.9	1.2	18.1
22	**Darlington Water Treatment Plant Lease**	0.0	0.0	0.0
23	**Darlington Spacer Retrieval[4]**	0.0	0.0	0.0
24	**Pickering Extended Operations**	0.0	0.0	0.0
25	**Minor Fixed Assets**	18.7	(7.3)	11.4
26	**Total In-Service Capital Additions**	477.3	(129.0)	348.3

Notes:

1 In-service additions per EB-2016-0152, Ex. J21.1, Attachment 2, Table 2. Amounts in this schedule do not reflect OEB-ordered reductions for: Auxiliary Heating System in-service amount (EB-2016-0152 Decision and Order, p. 21); Operations Support Building in-service amount (EB-2016-0152 Decision and Order, p. 22). These reductions are reflected in total nuclear rate base amounts in Ex. B3-2-1, Table 1. The 2017-2020 sub-components within the total portfolio in service forecast has also been adjusted for reclassification of projects from Darlington to Operations and Projects Support with no change to total amount.

2 Includes Engineering, Inspection and Reactor Innovation, and Security & Emergency Services.

3 Supplemental forecast to reconcile BCS in-service estimates to final business plan (see Ex. D2-1-3, Section 4.0).

4 Project #82949 DN X-750 Spacer Retrieval CMFA. OEB Approved amounts for Darlington Spacer Retreival per EB-2016-0152, Schedule 1, Staff-024, which were reflected in EB-2016-0152 Ex. J21.1, Attachment 2, Table 1.